PSEG

Public Service Electric and Gas Company P.O. Box 236 Hancocks Bridge, New Jersey 08038-0236

Nuclear Business Unit

LRN-00-0180

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Gentlemen:

UPDATED FINAL SAFETY ANALYSIS REPORT, REVISION 18
SALEM CREEK GENERATING STATION
DOCKET NO. 50-272 and 50-311

Public Service Electric and Gas Company (PSE&G) hereby submits Revision No. 18 to the Salem Station Updated Final Safety Analysis Report (UFSAR) in accordance with the requirements of 10CFR50.71(e).

Revision No. 18 to the Salem UFSAR contains identified text, table and figure changes required to reflect the plant configuration as of October 26, 1999, six months prior to this submittal. In addition, there are corrections of typographical errors and general editorial changes. Details regarding each change are attached to facilitate your review.

The previous revision to the Salem UFSAR was issued on October 16, 1998.

Should there be any questions regarding this submittal, please do not hesitate to contact us.

Sincerely,

M. B. Bezilla
Vice President - Operations

PSE&G
CONTROL
COPY # SESR0001

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Attachments:
- Affidavit
- Summary of Salem UFSAR Revision 18 Changes
- Salem UFSAR Revision No. 18

C Document Control Desk - Original & ten copies

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Vice President - Plant Support (X10)
Director - QA/NT/EP (120)
Manager - Licensing (N21)
Program Manager - NRB (N38)
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(w/ attachments except Salem UFSAR Revision No. 18):
Records Management
Microfilm
File Nos. 1.2.1, 2.1.3

REF: LRN-00-0180

STATE OF NEW JERSEY)
) SS.
COUNTY OF SALEM)

M. B. Bezilla, being duly sworn, states that he is Vice President – Operations of Public Service Electric and Gas Company, that he is authorized on the part of said Company to sign and file with the Nuclear Regulatory Commission this certification; and that in accordance with 10CFR50.71(e)(2), the information contained in the attached letter and Updated Final Safety Analysis Report accurately presents changes made since the previous submittal, necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirement, and contains an identification of changes made under the provisions of 10CFR50.59 but not previously submitted to the Commission.

Subscribed and Sworn to before me
this 26 th day of April, 2000

S/
Sheri A Hutton
Notary Public of New Jersey

My Commission expires on 12/8/2003

ATTACHMENT 1

Summary of Salem UFSAR Revision 18 Changes

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 95-071	9.1	9.1-2	Change fuel enrichment (data was later superceded by SCN 00-007)	Copy of TS Amendments 223 & 204 with Change Notice
SCN 96-143	6.2, 15.4	6.2-29 to 37, 39 & 40;15.4-99 to 106	Update technical information on CFCUs (blended with SCNs 97-050 & 97-116)	Copy of Safety Evaluation with Change Notice.
SCN 97-035	1.4, 3.2, 3.6, 3.7, 3.8, 3.9, 5.1, 5.2, 5.3, 5.5, 5.6, 6.3, 7.6, 10.3, 10.4, 11.1, 15.4, App3B,	1.4-2; 3.6-1, 1a, b, c, d, 2, 16, 17, 22, 31, 32, 35, 36, & 55, T3.6-1, F3.6-2, 4, 5, 8, 8a, 10, & 10a; 3.7-1; 3.8-74; 3.9-1, F3.9-1; 5.1-4, T5.1-1, F5.1-3 &3a; 5.2-14, 27, 28, 31, 35, 39, T5.2-2, 3, 5, 5a, 9a, 10, 16 to 27, & 33 to 36, F5.2-7 to 10, & 22 to 24; 5.3-2; 5.5-10 to 15, 17, 24, 58 to 59a, & 60, 5.6-7; 6.3-32; 7.6-6 & 8; 10.3-2, 4, 9, 10, 14 to 15b, F10.4-5a, 7 to 12, & 18a; T11.1-7, 10; T15.4-21; App 3B (all).	Steam generator replacement project	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-048	9.4	9.4-20	Revise description per design changes (supercedes SCN 97-089)	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-049	10.4	10.4-6, 10.4-7	Update discussion of Steam Dump Radiological Consequences	Copy of Safety Evaluation with Change Notice.
SCN 97-050	6.1, 6.2, 9.2, 15.4	6.1-7, 6.2-29 to 37, 39 & 40, T6.2-7; 9.2-2, 4, 7 to 8b, 10 & 11; 15.4-99 to 102	CFCU Thermal Overpressure Protection - Design Change Package 2EC-3590	Copy of Safety Evaluation with Change Notice. Field work is completed.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 97-050	6.1, 6.2, 9.2, 15.4	6.1-7, 6.2-29 to 37, 39 & 40, T6.2-7; 9.2-2, 4, 7 to 8b, 10 & 11; 15.4-99 to 102	CFCU Thermal Overpressure Protection - Design Change Package 2EC-3590	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-060	9.4	9.4-1, 9.4-1a	Describe Work Control Center air conditioning system (DCP 1EC-3505)	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-084	9.1	9.1-30	Revise to show addition of the reconstitution basket and hardtop assembly for Salem Unit 1.	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-088	10.2	10.2-1	Describe Main Generator Voltage Regulator replacement	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-090	4.2, 5.2, 6.2, 6.3, 6.4, 8.1, 8.3, 17.2	4.2-44; 5.2-55, T5.2-8; 6.2-13, 27, 59 & 63; 6.4-1, 1a, 1b, 1d, 4; 8.1-7; 8.3-14, 17, 20, T8.3-2; 17.2-7 & 19.	Correct misc. typographical errors, two incorrect references to T6.4-4, and correct the incomplete incorporation of a previous change notice on 2 pages.	Copy of Applicability Review with Change Notice.
SCN 97-092	6.3	T6.3-5	Correct Table to reflect work done by mod S97-099	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-116	9.2,	9.2-4, 8, 8a & 8b	Unit 1 CFCU modifications - blended with SCNs 96-143 & 97-050	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 97-126	9.2	9.2-4, 8, 8a & 8b	Unit 2 CFCU modifications - blended with SCNs 96-143 & 97-050	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-003	9.4	9.4-6, 7, 11 & 15	Incorporates results of Aux Bldg flow balancing (DCP 1EC-3311)	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-012	8.3	8.3-6	Reflects the uprating of the 115VAC vital instr. bus inverters from 10 to 12 kVA	Copy of Safety Evaluation with Change Notice. Field work is completed.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 98-021	9.3	9.3-14, 9.3-15	Reflect change to condensate drain piping from room cooler drip pans to floor	Copy of Safety Evaluation with DCP 1EC-3393. Field work is completed.
SCN 98-023	17.2	17.2-7b	Adds Licensing rep to SORC	Copy of Safety Evaluation with Change Notice.
SCN 98-026	15.4	15.4-63 & 130a	Adds information regarding a fuel handling accident within containment	Copy of Safety Evaluation with Change Notice.
SCN 98-028	6.3	6.3-17	Clarifies paragraph requiring Welding Procedure Specifications needing review & approval by Westinghouse	Copy of Applicability Review with Change Notice
SCN 98-029	9.3	9.3-1	Reflect modifications to station air compressor controls	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-031	9.5	9.5-26	Revise to mention portable hand-held lights for App R Safe Shutdown Emergency Lighting system	Copy of Safety Evaluation with Change Notice.
SCN 98-032	10.4	T10.4-1	Reflect the replacement of LP Feedwater heaters 23 A, B, C, & 24 A, B, C	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-033	13.5	13.5-2c	Clarify Chemistry Dept role with respect to procedures	Copy of Applicability Review with Change Notice
SCN 98-034	10.4	10.4-9	Correct description to agree with F10.4-3	Applicability Review with Change Notice
SCN 98-035	9.1	9.1-13	Adds clarification of SFP tell-tale design function	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-036	7.7	7.7-19, 7.7-20	Clarify description of console group alarms	Applicability Review with Change Notice

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 98-037	3A, 12.3, 12.4, 13.1	3A-53, 54; 12.3-1, 2; 12.4-1, 2; T13.1-1	Reflect Radiation Protection Dept reorganization	Copy of Safety Evaluation with Change Notice.
SCN 98-038	10.3, 10.4	10.3-18, 19; 10.4-11	ETA feedwater iron transport reduction test	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-039	3A, 3.2, 9.1	3A-11, 3.2-5,6; 9.1-5, 7, 10, 10, 11, 12, 14, 15 & T9.1-2	Describes seismic upgrade of SFP cooling system to preclude boiling as a credible event	Copy of Safety Evaluation with Change Notice.
SCN 98-042	7.2	7.2-9	Describes SSPS input bay wring per DCP	Copy of Safety Evaluation with Change Notice. Field work is completed.
SCN 98-043	7.7	7.7-29	Changed to reflect TS Amendment 62/33	Copy of Applicability Review with Change Notice
SCN 98-044	17.2	17.2-7	Clarify requirement for SQR review	Copy of Applicability Review with Change Notice
SCN 99-003	8.1	8.1-10	Removes limit on circuit breaker amps for 28 VDC logic system (DCP 1EE-0116)	Copy of Safety Evaluation with Design Change Package.
SCN 99-004	13.1	13.1-2, 13.1-16	Revise to reflect Chemistry reorganization	Copy of Safety Evaluation with Change Notice.
SCN 99-005	6.2	T6.2-10	Correct Table to agree with Sect. 9.4.4.2	Copy of Applicability Review with Change Notice
SCN 99-006	13.1, 17.2	13.1-8a; 17.2-4, T17.2-1	Reflect organizational change	Copy of Safety Evaluation with Change Notice.
SCN 99-007	4.3, 14.4	4.3-28, 29; 14.4-5, 6	Clarify startup and reload testing	Copy of Safety Evaluation with Change Notice.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 99-008	10.3	10.3-17	Change to allow on-line testing of MSSVs	Copy of Safety Evaluation with Change Notice.
SCN 99-009	8.2	8.2-3	Rename Keeney line as Red Lion line	Copy of Safety Evaluation with Change Notice.
SCN 99-010	9.4	9.4-17, 19	Removes statement regarding FHV ability to meet single failure criteria (NRC OIL # 50-311/96-080-01)	Copy of Safety Evaluation with Change Notice.
SCN 99-013	8.3	8.3-17	Describes modification which installed a disconnect switch in each 125 VDC bus.	Copy of Safety Evaluation with DCP 1EC-3637. Field work is completed.
SCN 99-014	3.8, 17.2	3.8-58, 64; T17.2-1	Expand usage of Containment Equipment Hatch	Copy of Safety Evaluation with Change Notice.
SCN 99-015	4.5	T4.5-2	Reflect the Reload Safety Evaluation revision number	Copy of Safety Evaluation with Change Notice.
SCN 99-016	9.2	9.2-6a	Clarify the rated performance of SW pumps (DCPs 1EE-0390 & 2EE-0330)	Copy of Safety Evaluation with DCPs. Field work is completed.
SCN 99-017	15.1, 15.2, 15.4	15.1-7, 9, T15.1-3; T15.2-1; 15.4-74	Changes "rod drop time" descriptions to be consistent with Tech Specs	Copy of Applicability Review with Change Notice

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 99-018	4.1, 4.2, 4.3, 4.4, 4.5	4.1-1, 2, 4; 4.2-2, 8 to 12, 13a, 13b, 13c, 25, 26, 28, 83; 4.3-10, 44; 4.4-2 to 10, 13 to 15a, 17, 19 to 21a,, 24, 25, 29, 31, 34, 35, 37, 38, 53, 54, 66a; T4.1-1, T4.3-1, 4.4-1, 4.4-2, 4.5-2, F4.2-1, F4.2-2b, F4.2-3b, F4.4-1, F4.4-1a, F4.4-2, F4.4-2a, F4.4-5c, F4.5-3, F4.5-4	Revise Chapter 4.0 of the UFSAR for the reload core design for Salem 2 Cycle 11. Changes reflect the use of Westinghouse new fuel assembly design (RFA) and the use of a new DNB correlation for critical heat flux predictions.	Copy of Safety Evaluation with Change Notice.
SCN 99-019	5.2, 9.3	T5.2-28; 9.3-24, 34	Change RCS dissolved hydrogen limit	Copy of Safety Evaluation with Change Notice.
SCN 99-022	6.3	6.3-15, 19	Clarifies that RHR HX channel cover mat'l is an equivalent corrosion-resistant material (SA 105 w/304 SS overlay)	Copy of Applicability Review with Change Notice
SCN 99-024	11.4	11.4-21, 22	Corrects Sect. 11.4.3 to agree with 11.2-5	Copy of Applicability Review with Change Notice
SCN 99-026	13.1	13.1-3b, 6b	Reorganization change (OE Group)	Copy of Safety Evaluation with Change Notice.
SCN 99-028	5.1, 5.5	5.1-5; 5.5-54	Reflect that RCS valve gland leakoff lines have been capped (DCP 1EE-0405)	Copy of Safety Evaluation with Change Notice.
SCN 99-035	7.3	7.3-32, 33	Reflect valve electrical interlocks of Unit 2 Semi-Automatic Switchover from injection to recirc phase	Copy of Safety Evaluation with Change Notice.
SCN 99-036	7.7	7.7-17, 17a, 17b, 18, 19, 20	Reflect replacement of the Unit 1 Auxiliary Annunciator system	Copy of Safety Evaluation with DCP 1EC-3733.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 99-037	13.5, App A	13.5-2a, A-36a, A-37 to 39, A-41, A-41a, TA-4, TA-5	Delete reference to Action Tracking Program and TRIS in UFSAR	Copy of Safety Evaluation with Change Notice.
SCN 99-038	15.4	15.4-49 to 51, 53, 55, 130a, T15.4-7b	Clarify relationship between operator action time assumptions and the actual allowableoperator action times.	Copy of Applicability Review with Change Notice
SCN 99-039	6.3	6.3-29, T6.3-7	Revise description of ECCS pumps to reflect use of class B or better insulation.	Copy of Applicability Review with Change Notice
SCN 99-040	7.7	7.7-6, 7.7-30	Adds reference for control rod timing per DCP	Copy of Safety Evaluation with DCP 1EC-3338.
SCN 99-043	8.3	T8.3-6	Revise 125 VDC battery load profile to reflect as-built LOCA peak loads.	Copy of Safety Evaluation with Change Notice.
SCN 99-045	3.2, 9.2	3.2-8; 9.2-9a	Clarify the weld inspection criteria for Class III weld joints	Copy of Applicability Review with Change Notice
SCN 99-046	3A, 9.5, 12.1, 12.3, 12.4, 13.1, 13.5, 17.2	3A-53; 9.5-2,3;12.1-13; 12.3-1; 12.4-2; 13.1-1, 1a, 2, 2a, 2b, 3a, 3b, 8a, 9, 10, 16, 18a, T13.1-1, F13.1-1 to 4, 8a, 8e; 13.5-1; 17.2-3, 12, 16, 20, 22, 28, 29, 38	Reflect senior management changes	Copy of Safety Evaluation with Change Notice.
SCN 99-047	4.5	T4.5-1	RSE & NDR for Salem Unit 1 Cycle 13 are revised. Shows revision numbers in UFSAR	Copy of Safety Evaluation with Change Notice.
SCN 99-048	9.3	9.3-16, 21, 25, 36	Support chemical degassing	Copy of Safety Evaluation with Change Notice.
SCN 99-049	6.2	6.2-59, 59a, F6.2-35, 45e	Correct to agree with UFSAR Figures	Applicability Review with Change Notice

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 99-057	15.4	T15.4-7	Correct discrepancy between UFSAR and the DBA dose consequence analysis.	Applicability Review with Change Notice
SCN 99-058	7.3	7.3-23, 25	Change description of initiation circuitry for addition of alternate relays to Containment Ventilation isolation actuation circuitry.	Copy of Safety Evaluation with Change Notice.
SCN 99-059	10.4, 11.2	10.4-24 to 27,T10.4-3, 4, 5, 6, F10.4-19; 11.2-3, 10, 10A, 12, 17	Show increase of SG Blowdown to minimize SG tube corrosion	Copy of Safety Evaluation with Change Notice.
SCN 99-060	4.2, 4.3, 4.5	4.2-46, 47, 53 to 55, 83, T4.2-2, F4.2-16, 17, 17a, 19; 4.3-12, 23, 26, 61, T4.3-1; T4.5-1, F4.5-1, 2	Salem 1 Cycle 14 reload core design with a new secondary source design and the use of a discrete burnable absorber design.	Copy of Safety Evaluation with Change Notice.
SCN 99-061	7.2	7.2-25	Reflect changes due to Digital Feedwater Controls (DCP 1EC-3206)	Copy of Safety Evaluation with Change Notice.
SCN 99-064	4.5	T4.5-1, F4.5-1,2	Unit 1 Cycle 14 considerations (This SCN was blended with SCNs 99-060 & 99-070)	Copy of Safety Evaluation with Change Notice.
SCN 99-065	17.2	17.2-7g, 40	Changes "audit schedule" to "audit plan".	Applicability Review with Change Notice
SCN 99-066	6.3	6.3-63	Correct text to agree with F6.3-1a	Applicability Review with Change Notice
SCN 99-067	7.5	T7.5-1, 2	Clarify level channel units of measure.	Applicability Review with Change Notice
SCN 99-068	11.1	T11.1-1	Delete reference to previously deleted	Applicability Review with Change Notice

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 99-069	3.5, 10.2	3.5-18; 10.2-6b, 7	Incorporate TS Turbine Overspeed Protection requirements	TS Amendment 224/205 and Applicability Review in CN package
SCN 99-070	4.5	T4.5-1, F4.5-1,2	Unit 1 Cycle 14 considerations (This SCN was blended with SCNs 99-060 & 99-064)	Copy of Safety Evaluation with Change Notice.
SCN 99-073	13.1	13.1-2a, 9	Transfer responsibility for oversight of contract maintenance services.	Copy of Safety Evaluation with Change Notice.
SCN 00-002	2.3	2.3-10, 10a, 11, T2.3-9, 10, 13, 14, 15, F2.3-7, Appx 2.3A	Corrects discrepancies in Met tower instrument elevations	Applicability Review with Change Notice
SCN 00-004	6.2, 15.1, 15.2, 15.3, 15.4	6.2-29, 31, 36, 37; 15.1-4 to 6, 8, 10 to 12, 14, 19 to 22, 24, 25, T15.1-1, 2, 3, F15.1-1 to 9; 15.2-6 to 13, 15, 16, 18, 20 to 23, 27 to 36, 38 to 43, 43b, 44 to46, 48 to 51,53 to 55, 57 to 59,62,T15.2-1,F15.2-4 TO 10, 12 TO 15, 19 to 46; 15.3-1, 5, 8, 11, 13, 15, 16, 20, 21, T15.3-4, F15.3-14 to 16b; 15.4-31, 32, 34, 35, 38, 39, 40, 43, 47, 48, 58, 59, 60a, 66, 68, 69, 74, 75, 75a, 77, 79 to 81, 83, 85, 88, 89, 96, 100, 101, 109, 110, 115, 118, 121, 126, 130, T15.4-1, 6, 12, 22, 23, 24, F15.4-48 to 54, 60a to 60e,68 to 72, 75 to 78b, 85, 96, 98, 100	Margin Recovery/ Steam Generator Replacement	Applicability Review with Change Notice

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 00-007	4.1, 4.2, 4.3, 9.1	4.1-2, T4.1-1; 4.2-9, 4.2-10; 4.3-45, 4.3-57, 4.3-61, T4.3-1; 9.1-2, 9.1-3, 9.1-40	Revise UFSAR due to annular pellets in RFA fuel. Also, LCR S98-17 was approved by the NRC.	Applicability Review with Change Notice
SCN 00-008	13.1, 17.2	13.1-6b, 13.1-8; 17.2-4a, F17.2-1	QA reorganization	Copy of Safety Evaluation with Change Notice.
		In addition, the following Figures have been revised due to drawing update activity:		
		F5.1-6a Sh 1	F9.2-1A Sh5	F9.3-4A Sh3
		F5.1-6b Sh 1	F9.2-1B Sh1	F9.3-4B Sh1
		F5.1-6b Sh 3	F9.2-1B Sh2	F9.3-4B Sh3
		F5.5-2a Sh1	F9.2-1B Sh3	F9.3-5A Sh1
		F5.5-2a Sh2	F9.2-1B Sh5	F9.3-5A Sh2
		F5.5-2b Sh1	F9.2-1B Sh6	F9.3-5B Sh1
		F5.5-2b Sh2	F9.2-4B Sh2	F9.3-5B Sh2
		F6.2-4A	F9.2-11 Sh6	F9.3-6A Sh1
		F6.2-4B	F9.2-11 Sh7	F9.3-6A Sh2
		F6.3-1A Sh1	F9.3-1A Sh1	F9.3-6B Sh1
		F6.3-1A Sh2	F9.3-1A Sh3	F9.3-7A Sh1
		F6.3-1B Sh1	F9.3-1B Sh1	F9.3-7A Sh2
		F8.3-4A	F9.3-2A Sh1	F9.3-7B Sh1
		F8.3-4C	F9.3-2A Sh2	F9.3-7B Sh2
		F8.3-7	F9.3-2A Sh3	F9.3-8A
		F8.3-8 Sh1	F9.3-2B Sh1	F9.3-8B
		F8.3-8 Sh2	F9.3-2B Sh2	F9.4-1A
		F9.1-4A	F9.3-2B Sh3	F9.4-1B
		F9.1-4B	F9.3-3A Sh1	F9.4-2A Sh1
		F9.2-1A Sh1	F9.3-3A Sh3	F9.4-2A Sh2
		F9.2-1A Sh2	F9.3-3B Sh1	F9.4-2A Sh3
		F9.2-1A Sh3	F9.3-3B Sh2	F9.4-2B Sh1
		F9.2-1A Sh4	F9.3-3B Sh3	F9.4-2B Sh2

F9.4-2B Sh3
F9.4-3A
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F9.4-4A Sh1
F9.4-4A Sh2
F9.4-4A Sh3
F9.4-4B Sh1
F9.4-4B Sh2
F9.4-4B Sh3
F9.4-6A
F9.5-2 Sh1
F9.5-2 Sh2
F9.5-2 Sh3
F10.2-1 Sh2
F10.2-1 Sh3
F10.2-2A Sh1
F10.2-2A Sh2
F10.2-2A Sh3
F10.2-2B Sh2
F10.2-2B Sh3
F10.2-3 Sh1
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F10.2-4 Sh2
F10.2-4 Sh3
F10.3-1A Sh1
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F10.3-1A Sh4
F10.3-1A Sh5
F10.3-1A Sh6
F10.3-1B Sh1
F10.3-1B Sh2
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F10.3-1B Sh4
F10.3-1B Sh6
F10.3-3 Sh1
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F10.4-1 Sh2
F10.4-2
F10.4-3A Sh1
F10.4-3A Sh2
F10.4-3A Sh3
F10.4-3A Sh5
F10.4-3B Sh1
F10.4-3B Sh2
F10.4-3B Sh3
F10.4-5A Sh 1
F10.4-5A Sh3
F10.4-5B Sh1
F10.4-5B Sh2
F10.4-5B Sh3
F10.4-6A Sh5
F10.4-6B Sh3
F10.4-6B Sh5
F10.4-17A
F10.4-17B
F10.4-18A Sh 1
F10.4-18A Sh2
F10.4-18B Sh1
F10.4-18B Sh2
F11.2-1A Sh3
F11.2-1B Sh1
F11.2-1B Sh2
F11.2-1B Sh3
F11.3-1A Sh1
F11.3-1A Sh2
F11.3-1B Sh1
F11.3-1B Sh2

REMOVE	& INSERT	REMOVE	& INSERT	REMOVE	& INSERT
1.4-1/2	1.4-1/2	4.1-1/2	4.1-1/2	4.4-17/17a	4.4-17/17a
2.3-9/10	2.3-9/10	4.1-3/4	4.1-3/4	4.4-19/20	4.4-19/20
2.3-10a/10b	2.3-10a/10b	T4.1-1 p1	T4.1-1 p1	4.4-21/21a	4.4-21/21a
2.3-11/12	2.3-11/12	T4.1-1 p3	T4.1-1 p3	4.4-21b/22	4.4-21b/22
T2.3-9 p1	T2.3-9 p1	T4.1-1 p4	T4.1-1 p4	4.4-23/24	4.4-23/24
T2.3-10 p1	T2.3-10 p1	T4.1-1 p5	T4.1-1 p5	4.4-25/26	4.4-25/26
T2.3-13 p1	T2.3-13 p1	4.2-1/2	4.2-1/2	4.4-29/30	4.4-29/30
T2.3-14 p1	T2.3-14 p1	4.2-7/8	4.2-7/8	4.4-31/32	4.4-31/32
T2.3-15 p1	T2.3-15 p1	4.2-9/10	4.2-9/10	4.4-33/34	4.4-33/34
F2.3-7	F2.3-7	4.2-11/12	4.2-11/12	4.4-35/36	4.4-35/36
App2.3A	App2.3A	4.2-13/13a	4.2-13/13a	4.4-37/38	4.4-37/38
2.3A-1/66	- - - -	4.2-13b/13c	4.2-13b/13c	4.4-53/54	4.4-53/54
3-iii/iv	3-iii/iv	4.2-25/26	4.2-25/26	4.4-66a/66b	4.4-66a/66b
3.2-5/6	3.2-5/6	4.2-27/28	4.2-27/28	- - - -	4.4-66c/66d
3.2-7/8	3.2-7/8	4.2-43/44	4.2-43/44	T4.4-1 p1	T4.4-1 p1
3.5-17/18	3.5-17/18	4.2-45/46	4.2-45/46	T4.4-1 p2	T4.4-1 p2
3.6-1/2	3.6-1/1a	4.2-47/48	4.2-47/48	T4.4-1 p3	T4.4-1 p3
- - - -	3.6-1b/1c	4.2-53/54	4.2-53/54	T4.4-1 p4	- - - -
- - - -	3.6-1d/2	4.2-55/56	4.2-55/56	T4.4-2 p1	T4.4-2 p1
3.6-15/16	3.6-15/16	4.2-67/68	4.2-67/68	T4.4-2 p2	- - - -
3.6-17/18	3.6-17/18	4.2-83	4.2-83	F4.4-1	F4.4-1
3.6-21b/22	3.6-21b/22	- - - -	T4.2-2 p 1	- - - -	F4.4-1A
3.6-31/32	3.6-31/32	F4.2-1	F4.2-1	F4.4-2	F4.4-2
3.6-35/36	3.6-35/36	- - - -	F4.2-2B	- - - -	F4.4-2A
3.6-55	3.6-55	- - - -	F4.2-3B	- - - -	F4.4-5C
T3.6-1 p1	T3.6-1 p1	F4.2-16	F4.2-16	T4.5-1 p1	T4.5-1 p1
F3.6-2	F3.6-2	F4.2-17	F4.2-17	T4.5-2 p1	T4.5-2 p1
F3.6-4	F3.6-4	- - - -	F4.2-17a	F4.5-1	F4.5-1
F3.6-5	F3.6-5	F4.2-19	F4.2-19	F4.5-2	F4.5-2
F3.6-8	F3.6-8	4.3-9/10	4.3-9/10	F4.5-3	F4.5-3
- - - -	F3.6-8a	4.3-11/12	4.3-11/12	F4.5-4	F4.5-4
F3.6-10	F3.6-10	4.3-23/24	4.3-23/24	5.1-3/4	5.1-3/4
- - - -	F3.6-10a	4.3-25/26	4.3-25/26	5.1-5/6	5.1-5/6
3.7-1/2	3.7-1/2	4.3-27/28	4.3-27/28	T5.1-1 p1	T5.1-1 p1
3.8-57/58	3.8-57/58	4.3-29/30	4.3-29/30	T5.1-1 p2	- - - -
3.8-63/64	3.8-63/64	4.3-43/44	4.3-43/44	F5.1-3	F5.1-3
3.8-73/74	3.8-73/74	4.3-45/46	4.3-45/46	- - - -	F5.1-3a
3.9-1/2	3.9-1/2	4.3-57/58	4.3-57/58	F5.1-6a Sh1	F5.1-6a Sh1
F3.9-1	F3.9-1	4.3-61	4.3-61	F5.1-6b Sh1	F5.1-6b Sh1
3.12-1/2	3.12-1/2	T4.3-1 p1	T4.3-1 p1	F5.1-6b Sh3	F5.1-6b Sh3
3A-11/12	3A-11/12	T4.3-1 p2	T4.3-1 p2	5.2-13/14	5.2-13/14
3A-53/54	3A-53/54	T4.3-1 p3	T4.3-1 p3	5.2-27/28	5.2-27/28
- - - -	App 3B	4.4-1/2	4.4-1/2	5.2-31/32	5.2-31/32
4-v/vi	4-v/vi	4.4-2a/2b	4.4-2a/2b	5.2-35/36	5.2-35/36
4-vii/viii	4-vii/viii	4.4-3/4	4.4-3/4	5.2-39/40	5.2-39/40
4-ix/x	4-ix/x	4.4-5/6	4.4-5/6	5.2-55/56	5.2-55/56
4-xi/xii	4-xi/xii	4.4-7/8	4.4-7/8	T5.2-2 p1	T5.2-2 p1
4-xiii/xiv	4-xiii/xiv	4.4-9/10	4.4-9/10	T5.2-3 p2	T5.2-3 p2
4-xv	4-xv	4.4-13/14	4.4-13/14	T5.2-5 p1	T5.2-5 p1
		4.4-15/15a	4.4-15/15a	T5.2-5 p2	T5.2-5 p2

REMOVE	& INSERT	REMOVE	& INSERT	REMOVE	& INSERT
- - - -	T5.2-5a p1	6.1-7/8	6.1-7/8	8.2-3/4	8.2-3/4
T5.2-8 p2	T5.2-8 p2	6.2-13/14	6.2-13/14	8.3-5b/6	8.3-5b/6
T5.2-9a p1	T5.2-9a p1	6.2-27/28	6.2-27/28	8.3-13/14	8.3-13/14
- - - -	T5.2-9a p2	6.2-29/30	6.2-29/30	8.3-17/18	8.3-17/18
T5.2-10 p1	T5.2-10 p1	6.2-31/32	6.2-31/32	8.3-19/20	8.3-19/20
T5.2-10 p2	T5.2-10 p2	6.2-33/34	6.2-33/34	T8.3-2 p1	T8.3-2 p1
- - - -	T5.2-10a p1	6.2-35/36	6.2-35/36	T8.3-6 p1	T8.3-6 p1
- - - -	T5.2-10a p2	6.2-37/38	6.2-37/38	F8.3-4A	F8.3-4A
T5.2-16 p1	T5.2-16 p1	6.2-39/40	6.2-39/40	F8.3-4C	F8.3-4C
T5.2-17 p1	T5.2-17 p1	6.2-59/59a	6.2-59/59a	F8.3-7	F8.3-7
T5.2-18 p1	T5.2-18 p1	T6.2-7 p1	T6.2-7 p1	F8.3-8 Sh1	F8.3-8 Sh1
T5.2-19 p1	T5.2-19 p1	T6.2-10 p6	T6.2-10 p6	F8.3-8 Sh2	F8.3-8 Sh2
T5.2-20 p1	T5.2-20 p1	T6.2-10 p9	T6.2-10 p9	9.1-1/2	9.1-1/2
T5.2-21 p1	T5.2-21 p1	F6.2-4A	F6.2-4A	9.1-3/3a	9.1-3/3a
T5.2-22 p1	T5.2-22 p1	F6.2-4B	F6.2-4B	9.1-5/6	9.1-5/6
T5.2-23 p1	T5.2-23 p1	F6.2-35	F6.2-35	9.1-7/8	9.1-7/8
T5.2-24 p1	T5.2-24 p1	F6.2-45E	F6.2-45E	9.1-9/10	9.1-9/10
T5.2-25 p1	T5.2-25 p1	6.3-15/16	6.3-15/16	9.1-10a/10b	9.1-10a/10b
T5.2-26 p1	T5.2-26 p1	6.3-17/18	6.3-17/18	9.1-11/12	9.1-11/12
T5.2-26 p2	T5.2-26 p2	6.3-19/20	6.3-19/20	9.1-13/14	9.1-13/14
T5.2-27 p1	T5.2-27 p1	6.3-29/30	6.3-29/30	9.1-15/16	9.1-15/16
T5.2-28 p1	T5.2-28 p1	6.3-31/32	6.3-31/32	9.1-29/30	9.1-29/30
- - - -	T5.2-33 p1	6.3-63/64	6.3-63/64	9.1-39/40	9.1-39/40
- - - -	T5.2-33 p2	T6.3-5 p1	T6.3-5 p1	F9.1-4A	F9.1-4A
- - - -	T5.2-34 p1	T6.3-7 p1	T6.3-7 p1	F9.1-4B	F9.1-4B
- - - -	T5.2-35 p1	F6.3-1A Sh1	F6.3-1A Sh1	T9.1-2 p1	T9.1-2 p1
- - - -	T5.2-36 p1	F6.3-1A Sh2	F6.3-1A Sh2	9.2-1/2	9.2-1/2
F5.2-7	F5.2-7	F6.3-1B Sh1	F6.3-1B Sh 1	9.2-3/4	9.2-3/4
F5.2-8	F5.2-8	6.4-1/1a	6.4-1/1a	9.2-6a/6b	9.2-6a/6b
F5.2-9	F5.2-9	6.4-1b/1c	6.4-1b/1c	9.2-7/8	9.2-7/8
F5.2-10	F5.2-10	6.4-1d/2	6.4-1d/2	- - - -	9.2-8a/8b
- - - -	F5.2-22	6.4-3/4	6.4-3/4	9.2-9/9a	9.2-9/9a
- - - -	F5.2-23	7.2-9/10	7.2-9/10	9.2-9b/10	9.2-9b/10
- - - -	F5.2-24	7.2-25/26	7.2-25/26	9.2-11/12	9.2-11/12
5.3-1/2	5.3-1/2	7.3-23/24	7.3-23/24	F9.2-1A Sh1	F9.2-1A Sh1
5.5-9/10	5.5-9/10	7.3-25/26	7.3-25/26	F9.2-1A Sh2	F9.2-1A Sh2
5.5-11/12	5.5-11/12	7.3-31b/32	7.3-31b/32	F9.2-1A Sh3	F9.2-1A Sh3
5.5-13/14	5.5-13/14	7.3-33/34	7.3-33/34	F9.2-1A Sh4	F9.2-1A Sh4
5.5-15/15	5.5-15/15	T7.5-1 p1	T7.5-1 p1	F9.2-1A Sh5	F9.2-1A Sh5
5.5-17/18	5.5-17/18	T7.5-1 p3	T7.5-1 p3	F9.2-1B Sh1	F9.2-1B Sh1
5.5-23/24	5.5-23/24	T7.5-2 p5	T7.5-2 p5	F9.2-1B Sh2	F9.2-1B Sh2
5.5-53/54	5.5-53/54	7.6-5/6	7.6-5/6	F9.2-1B Sh3	F9.2-1B Sh3
5.5-57/58	5.5-57/58	7.6-7/8	7.6-7/8		
5.5-59/59a	5.5-59/59a	7.7-5/6	7.7-5/6		
5.5-60	5.5-60	7.7-17/17a	7.7-17/17a		
F5.5-2a Sh1	F5.5-2a Sh1	7.7-17b/18	7.7-17b/18		
F5.5-2a Sh2	F5.5-2a Sh2	7.7-19/20	7.7-19/20		
F5.5-2b Sh1	F5.5-2b Sh1	7.7-29/30	7.7-29/30		
F5.5-2b Sh2	F5.5-2b Sh2	8.1-7/8	8.1-7/8		
5.6-7/8	5.6-7/8	8.1-9/10	8.1-9/10		

INSERTION INSTRUCTIONS

REMOVE	& INSERT	REMOVE	& INSERT	REMOVE	& INSERT
F9.2-1B Sh5	F9.2-1B Sh5	9.4-19/20	9.4-19/20	F10.3-1B Sh2	F10.3-1B Sh2
F9.2-1B Sh6	F9.2-1B Sh6	F9.4-1A	F9.4-1A	F10.3-1B Sh3	F10.3-1B Sh3
F9.2-4B Sh2	F9.2-4B Sh2	F9.4-1B	F9.4-1B	F10.3-1B Sh4	F10.3-1B Sh4
F9.2-11 Sh6	F9.2-11 Sh6	F9.4-2A Sh1	F9.4-2A Sh1	F10.3-1B Sh6	F10.3-1B Sh6
F9.2-11 Sh7	F9.2-11 Sh7	F9.4-2A Sh2	F9.4-2A Sh2	F10.3-3 Sh1	F10.3-3 Sh1
9.3-1/2	9.3-1/2	F9.4-2A Sh3	F9.4-2A Sh3	F10.3-3 Sh2	F10.3-3 Sh2
9.3-13/14	9.3-13/14	F9.4-2B Sh1	F9.4-2B Sh1	10.4-5/6	10.4-5/6
9.3-15/15a	9.3-15/15a	F9.4-2B Sh2	F9.4-2B Sh2	10.4-7/8	10.4-7/8
9.3-15b/16	9.3-15b/16	F9.4-2B Sh3	F9.4-2B Sh3	10.4-9/10	10.4-9/10
9.3-21/22	9.3-21/22	F9.4-3A	F9.4-3A	10.4-11/12	10.4-11/12
9.3-23/24	9.3-23/24	F9.4-3B	F9.4-3B	10.4-13/14	10.4-13/14
9.3-25/26	9.3-25/26	F9.4-4A Sh1	F9.4-4A Sh1	10.4-15/16	10.4-15/15a
9.3-33/34	9.3-33/34	F9.4-4A Sh2	F9.4-4A Sh2	- - - -	10.4-15b/16
9.3-35/36	9.3-35/36	F9.4-4A Sh3	F9.4-4A Sh3	10.4-23/24	10.4-23/24
F9.3-1A Sh1	F9.3-1A Sh1	F9.4-4B Sh1	F9.4-4B Sh1	10.4-25/26	10.4-25/26
F9.3-1A Sh3	F9.3-1A Sh3	F9.4-4B Sh2	F9.4-4B Sh2	10.4-27	10.4-27
F9.3-1B Sh1	F9.3-1B Sh1	F9.4-4B Sh3	F9.4-4B Sh3	T10.4-1p2	T10.4-1p2
F9.3-2A Sh1	F9.3-2A Sh1	F9.4-6A	F9.4-6A	T10.4-1p3	T10.4-1p3
F9.3-2A Sh2	F9.3-2A Sh2	9.5-1/2	9.5-1/2	T10.4-3 p1	T10.4-3 p1
F9.3-2A Sh3	F9.3-2A Sh3	9.5-3/4	9.5-3/4	T10.4-4 p1	T10.4-4 p1
F9.3-2B Sh1	F9.3-2B Sh1	9.5-25/26	9.5-25/26	T10.4-5 p1	T10.4-5 p1
F9.3-2B Sh2	F9.3-2B Sh2	F9.5-2 Sh1	F9.5-2 Sh1	T10.4-5 p2	- - - -
F9.3-2B Sh3	F9.3-2B Sh3	F9.5-2 Sh2	F9.5-2 Sh2	T10.4-6 p1	T10.4-6 p1
F9.3-3A Sh1	F9.3-3A Sh1	F9.5-2 Sh3	F9.5-2 Sh3	F10.4-1 Sh2	F10.4-1 Sh2
F9.3-3A Sh3	F9.3-3A Sh3	10-iii/iv	10-iii/iv	F10.4-2	F10.4-2
F9.3-3B Sh1	F9.3-3B Sh1	10.2-1/2	10.2-1/2	F10.4-3A Sh1	F10.4-3A Sh1
F9.3-3B Sh2	F9.3-3B Sh2	10.2-6a/6b	10.2-6a/6b	F10.4-3A Sh2	F10.4-3A Sh2
F9.3-3B Sh3	F9.3-3B Sh3	10.2-7/8	10.2-7/8	F10.4-3A Sh3	F10.4-3A Sh3
F9.3-4A Sh3	F9.3-4A Sh3	F10.2-1 Sh2	F10.2-1 Sh2	F10.4-3A Sh5	F10.4-3A Sh5
F9.3-4B Sh1	F9.3-4B Sh1	F10.2-1 Sh3	F10.2-1 Sh3	F10.4-3B Sh1	F10.4-3B Sh1
F9.3-4B Sh3	F9.3-4B Sh3	F10.2-2A Sh1	F10.2-2A Sh1	F10.4-3B Sh2	F10.4-3B Sh2
F9.3-5A Sh1	F9.3-5A Sh1	F10.2-2A Sh2	F10.2-2A Sh2	F10.4-3B Sh3	F10.4-3B Sh3
F9.3-5A Sh2	F9.3-5A Sh2	F10.2-2A Sh3	F10.2-2A Sh3	F10.4-5A Sh 1	F10.4-5A Sh 1
F9.3-5B Sh1	F9.3-5B Sh1	F10.2-2B Sh2	F10.2-2B Sh2	F10.4-5A Sh3	F10.4-5A Sh3
F9.3-5B Sh2	F9.3-5B Sh2	F10.2-2B Sh3	F10.2-2B Sh3	F10.4-5B Sh1	F10.4-5B Sh1
F9.3-6A Sh1	F9.3-6A Sh1	F10.2-3 Sh1	F10.2-3 Sh1	F10.4-5B Sh2	F10.4-5B Sh2
F9.3-6A Sh2	F9.3-6A Sh2	F10.2-3 Sh2	F10.2-3 Sh2	F10.4-5B Sh3	F10.4-5B Sh3
F9.3-6B Sh1	F9.3-6B Sh1	F10.2-4 Sh2	F10.2-4 Sh2	F10.4-6A Sh5	F10.4-6A Sh5
F9.3-7A Sh1	F9.3-7A Sh1	F10.2-4 Sh3	F10.2-4 Sh3	F10.4-6B Sh3	F10.4-6B Sh3
F9.3-7A Sh2	F9.3-7A Sh2	10.3-1/2	10.3-1/2	F10.4-6B Sh5	F10.4-6B Sh5
F9.3-7B Sh1	F9.3-7B Sh1	10.3-3/4	10.3-3/4	F10.4-7	F10.4-7
F9.3-7B Sh2	F9.3-7B Sh2	10.3-9/10	10.3-9/10	F10.4-5A Sh 3	F10.4-5A Sh 3
F9.3-8A	F9.3-8A	10.3-17/18	10.3-17/18	F10.4-8	F10.4-8
F9.3-8B	F9.3-8B	10.3-19	10.3-19	- - - -	F10.4-8a
9.4-1/1a	9.4-1/1a	F10.3-1A Sh1	F10.3-1A Sh1	F10.4-9	F10.4-9
9.4-5/6	9.4-5/6	F10.3-1A Sh2	F10.3-1A Sh2	F10.4-10	F10.4-10
9.4-7/8	9.4-7/8	F10.3-1A Sh4	F10.3-1A Sh4	F10.4-11	F10.4-11
9.4-11/12	9.4-11/12	F10.3-1A Sh5	F10.3-1A Sh5	F10.4-12	F10.4-12
9.4-15/16	9.4-15/16	F10.3-1A Sh6	F10.3-1A Sh6	F10.4-17A	F10.4-17A
9.4-17/18	9.4-17/18	F10.3-1B Sh1	F10.3-1B Sh1	F10.4-17B	F10.4-17B

REMOVE	& INSERT	REMOVE	& INSERT	REMOVE	& INSERT
F10.4-18A Sh1	F10.4-18A Sh1	15-ix/x	15-ix/x	15.2-37/38	15.2-37/38
F10.4-18A Sh2	F10.4-18A Sh2	15-xi/xii	15-xi/xii	15.2-39/40	15.2-39/40
F10.4-18B Sh1	F10.4-18B Sh1	15-xiii/xiiia	15-xiii/xiiia	15.2-41/42	15.2-41/42
F10.4-18B Sh2	F10.4-18B Sh2	15-xiiib/xiv	15-xiiib/xiv	15.2-43/43a	15.2-43/43a
F10.4-19	F10.4-19	15-xv/xvi	15-xv/xvi	15.2-43b/44	15.2-43b/44
T11.1-1 p1	T11.1-1 p1	15-xvii/xviii	15-xvii/xviii	15.2-45/46	15.2-45/46
T11.1-7 p1	T11.1-7 p1	15-xix/xixa	15-xix/xixa	15.2-47/48	15.2-47/48
T11.1-10 p2	T11.1-10 p2	15-xxiii/xxiiia	15-xxiii/xxiiia	15.2-49/50	15.2-49/50
11.2-3/4	11.2-3/4	15-xxiiib/xxiv	15-xxiiib/xxiv	15.2-51/51a	15.2-51/51a
11.2-9/10	11.2-9/10	15-xxiva/xxivb	15-xxiva/xxivb	15.2-53/54	15.2-53/54
11.2-10a/10b	11.2-10a/10b	15-xxv/xxvi	15-xxv/xxvi	15.2-55/56	15.2-55/56
11.2-11/12	11.2-11/12	15-xxvii/xxviii	15-xxvii/xxviii	15.2-57/58	15.2-57/58
11.2-17	11.2-17	15.1-3/4	15.1-3/4	15.2-59/60	15.2-59/60
F11.2-1A Sh3	F11.2-1A Sh3	15.1-5/6	15.1-5/6	15.2-61/62	15.2-61/62
F11.2-1B Sh1	F11.2-1B Sh1	15.1-7/8	15.1-7/8	T15.2-1 p1	T15.2-1 p1
F11.2-1B Sh2	F11.2-1B Sh2	15.1-9/10	15.1-9/10	T15.2-1 p2	T15.2-1 p2
F11.2-1B Sh3	F11.2-1B Sh3	15.1-11/12	15.1-11/12	T15.2-1 p3	T15.2-1 p3
F11.3-1A Sh1	F11.3-1A Sh1	15.1-13/14	15.1-13/14	T15.2-1 p4	T15.2-1 p4
F11.3-1A Sh2	F11.3-1A Sh2	15.1-19/20	15.1-19/20	T15.2-1 p5	T15.2-1 p5
F11.3-1B Sh1	F11.3-1B Sh1	15.1-21/22	15.1-21/22	T15.2-1 p6	T15.2-1 p6
F11.3-1B Sh2	F11.3-1B Sh2	15.1-23/24	15.1-23/24	- - - -	T15.2-1 p6a
11.4-21/22	11.4-21/22	15.1-25/26	15.1-25/26	T15.2-1 p7	T15.2-1 p7
12.1-13/14	12.1-13/14	T15.1-1 p1	T15.1-1 p1	- - - -	T15.2-1 p7a
12.3-1/2	12.3-1/2	T15.1-2 p1	T15.1-2 p1	T15.2-1 p8	T15.2-1 p8
12.4-1/2	12.4-1/2	T15.1-2 p2	T15.1-2 p2	F15.2-4	F15.2-4
13-iii/iv	13-iii/iv	T15.1-2 p3	T15.1-2 p3	F15.2-5	F15.2-5
13.1-1/1a	13.1-1/1a	T15.1-2 p4	T15.1-2 p4	F15.2-6	F15.2-6
13.1-1b/2	13.1-1b/2	T15.1-3 p1	T15.1-3 p1	F15.2-7	F15.2-7
13.1-2a/2b	13.1-2a/2b	F15.1-1	F15.1-1	F15.2-8	F15.2-8
13.1-3/3a	13.1-3/3a	F15.1-2	F15.1-2	F15.2-9	F15.2-9
13.1-3b/4	13.1-3b/4	F15.1-3	F15.1-3	F15.2-10	F15.2-10
13.1-6a/6b	13.1-6a/6b	F15.1-4	F15.1-4	F15.2-12	F15.2-12
13.1-7/8	13.1-7/8	F15.1-5	F15.1-5	F15.2-13	F15.2-13
13.1-8a/8b	13.1-8a/8b	F15.1-8	F15.1-8	F15.2-14	F15.2-14
13.1-9/10	13.1-9/10	F15.1-9	F15.1-9	F15.2-15	F15.2-15
13.1-15/16	13.1-15/16	15.2-5b/6	15.2-5b/6	F15.2-19	F15.2-19
13.1-18a/18b	13.1-18a/18b	15.2-7/8	15.2-7/8	F15.2-20	F15.2-20
T13.1-1 p1	T13.1-1 p1	15.2-9/10	15.2-9/10	F15.2-21	F15.2-21
F13.1-1	F13.1-1	15.2-11/12	15.2-11/12	F15.2-22	F15.2-22
F13.1-2	F13.1-2	15.2-13/14	15.2-13/14	F15.2-23	F15.2-23
F13.1-3	F13.1-3	15.2-15/16	15.2-15/16	F15.2-24	F15.2-24
F13.1-4	F13.1-4	15.2-17/18	15.2-17/18	F15.2-25	F15.2-25
F13.1-8A	F13.1-8A	15.2-19/20	15.2-19/20	F15.2-26	F15.2-26
F13.1-8E	F13.1-8E	15.2-21/22	15.2-21/22	F15.2-27	F15.2-27
13.5-1/2	13.5-1/2	15.2-23/24	15.2-23/24	F15.2-28	F15.2-28
13.5-2a/2b	13.5-2a/2b	15.2-27/28	15.2-27/28	- - - -	F15.2-28A
13.5-2c/2d	13.5-2c/2d	15.2-29/30	15.2-29/30	- - - -	F15.2-28B
14.4-5/6	14.4-5/6	15.2-31/32	15.2-31/32	- - - -	F15.2-28C
15-i/ii	15-i/ii	15.2-33/34	15.2-33/34	- - - -	F15.2-28D
15-iii/iv	15-iii/iv	15.2-35/36	15.2-35/36		

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REMOVE	& INSERT	REMOVE	& INSERT	REMOVE	& INSERT
- - - -	F15.2-28E	15.4-51/52	15.4-51/52	F15.4-49	F15.4-49
- - - -	F15.2-28F	15.4-53/54	15.4-53/54	F15.4-50A	F15.4-50A
F15.2-29A	F15.2-29A	15.4-55/56	15.4-55/56	F15.4-50B	F15.4-50B
F15.2-29B	F15.2-29B	15.4-57/58	15.4-57/58	F15.4-50C	F15.4-50C
F15.2-29C	F15.2-29C	15.4-59/60	15.4-59/60	F15.4-50D	F15.4-50D
F15.2-29D	F15.2-29D	15.4-60a/60b	15.4-60a/60b	F15.4-50E	F15.4-50E
F15.2-29E	F15.2-29E	15.4-61/62	15.4-61/62	F15.4-50F	F15.4-50F
F15.2-29F	F15.2-29F	15.4-63/64	15.4-63/64	F15.4-51A	F15.4-51A
F15.2-30	F15.2-30	15.4-65/66	15.4-65/66	F15.4-51B	F15.4-51B
F15.2-31	F15.2-31	15.4-67/68	15.4-67/68	F15.4-51C	F15.4-51C
F15.2-32	F15.2-32	15.4-69/70	15.4-69/70	F15.4-51D	F15.4-51D
F15.2-33	F15.2-33	15.4-73/74	15.4-73/74	F15.4-51E	F15.4-51E
F15.2-34	F15.2-34	15.4-75/75a	15.4-75/75a	F15.4-51F	F15.4-51F
F15.2-35	F15.2-35	15.4-77/78	15.4-77/78	F15.4-52A	F15.4-52A
F15.2-36	F15.2-36	15.4-79/80	15.4-79/80	F15.4-52B	F15.4-52B
F15.2-37	F15.2-37	15.4-81/82	15.4-81/82	F15.4-52C	F15.4-52C
F15.2-38	F15.2-38	15.4-83/84	15.4-83/84	F15.4-52D	F15.4-52D
F15.2-39	F15.2-39	15.4-85/86	15.4-85/86	F15.4-52E	F15.4-52E
F15.2-40	F15.2-40	15.4-87/88	15.4-87/88	F15.4-52F	F15.4-52F
F15.2-41	F15.2-41	15.4-89/90	15.4-89/90	F15.4-53A	F15.4-53A
F15.2-42	F15.2-42	15.4-95/96	15.4-95/96	F15.4-53B	F15.4-53B
F15.2-43A	F15.2-43A	15.4-99/100	15.4-99/100	F15.4-53C	F15.4-53C
F15.2-43B	F15.2-43B	15.4-101/102	15.4-101/102	F15.4-53D	F15.4-53D
F15.2-43C	F15.2-43C	15.4-103/104	15.4-103/104	F15.4-53E	F15.4-53E
F15.2-44	F15.2-44	15.4-105/106	15.4-105/106	F15.4-53F	F15.4-53F
F15.2-45	F15.2-45	15.4-109/110	15.4-109/110	F15.4-54	F15.4-54
F15.2-46	F15.2-46	15.4-111/112	15.4-111/112	F15.4-60A	F15.4-60A
15.3-1/2	15.3-1/2	15.4-113/114	15.4-113/114	F15.4-60B	F15.4-60B
15.3-5/6	15.3-5/6	15.4-115/116	15.4-115/116	F15.4-60C	F15.4-60C
15.3-7/8	15.3-7/8	15.4-117/118	15.4-117/118	- - - -	F15.4-60D
15.3-11/11a	15.3-11/11a	15.4-121/122	15.4-121/122	- - - -	F15.4-60E
15.3-13/14	15.3-13/14	15.4-125/126	15.4-125/126	- - - -	F15.4-60F
15.3-15/16	15.3-15/16	- - - -	15.4-130a	F15.4-68	F15.4-68
15.3-19/20	15.3-19/20	T15.4-1 p2	T15.4-1 p2	F15.4-69	F15.4-69
15.3-21	15.3-21	- - - -	T15.4-1 p2a	F15.4-70	F15.4-70
- - - -	T15.3-4 p1	T15.4-1 p3	T15.4-1 p3	F15.4-71	F15.4-71
F15.3-14	F15.3-14	- - - -	T15.4-1 p3a	F15.4-72	F15.4-72
F15.3-15	F15.3-15	- - - -	T15.4-1 p3b	F15.4-75	F15.4-75
F15.3-16	F15.3-16	T15.4-6 p1	T15.4-6 p1	F15.4-76	F15.4-76
- - - -	F15.3-16A	T15.4-7 p1	T15.4-7 p1	F15.4-77	F15.4-77
- - - -	F15.3-16B	T15.4-7b p1	T15.4-7b p1	F15.4-78	F15.4-78
15.4-31/32	15.4-31/32	T15.4-12 p1	T15.4-12 p1	- - - -	F15.4-78A
15.4-33/34	15.4-33/34	T15.4-21 sh2	T15.4-21 sh2	- - - -	F15.4-78B
15.4-35/36	15.4-35/36	T15.4-21 sh8	T15.4-21 sh8	F15.4-85	F15.4-85
15.4-37/38	15.4-37/38	T15.4-21 sh17	T15.4-21 sh17	F15.4-91	F15.4-91
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15.4-41/42	15.4-41/42	T15.4-22 p1	T15.4-22 p1	F15.4-98	F15.4-98
15.4-43/44	15.4-43/44	T15.4-23 p1	T15.4-23 p1	F15.4-100	F15.4-100
15.4-47/48	15.4-47/48	T15.4-24 p1	T15.4-24 p1	17.2-3/4	17.2-3/4
15.4-49/50	15.4-49/50	F15.4-48	F15.4-48	17.2-4a/4b	17.2-4a/4b

INSERTION INSTRUCTIONS

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17.2-7b/7c	17.2-7b/7c
17.2-7f/7g	17.2-7f/7g
17.2-11/12	17.2-11/12
17.2-15b/16	17.2-15b/16
17.2-19/20	17.2-19/20
17.2-21/22	17.2-21/22
17.2-27/28	17.2-27/28
17.2-29/30	17.2-29/30
17.2-37/38	17.2-37/38
17.2-39/40	17.2-39/40
T17.2-1 p3	T17.2-1 p3
F17.2-1	F17.2-1
A-36a/36b	A-36a/36b
A-37/38	A-37/38
A-39/40	A-39/40
A-41/41a	A-41/41a
TA-4 p1	TA-4 p1
TA-4 p2	TA-4 p2
TA-4 p3	TA-4 p3
TA-4 p4	TA-4 p4
TA-5 p1	TA-5 p1
TA-5 p2	TA-5 p2
TA-5 p3	TA-5 p3
TA-5 p4	TA-5 p4
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vi	9	2-xi	6	F2.1-2	6
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1.6-2	16	2.1-27	6	2.2-12a	16
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2.3-9	13	2.3A-6	D	2.3A-56	D
2.3-10	18	2.3A-7	D	2.3A-57	D
2.3-10a	18	2.3A-8	D	2.3A-58	D
2.3-10b	13	2.3A-9	D	2.3A-59	D
2.3-11	18	2.3A-10	D	2.3A-60	D
2.3-12	16	2.3A-11	D	2.3A-61	D
2.3-13	16	2.3A-12	D	2.3A-62	D
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2.3-14a	16	2.3A-14	D	2.3A-64	D
2.3-14b	16	2.3A-15	D	2.3A-65	D
2.3-15	16	2.3A-16	D	2.3A-66	D
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T2.3-13	18	2.3A-29	D	2.4-13	15
T2.3-14	18	2.3A-30	D	2.4-14	6
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1.4 IDENTIFICATION OF CONTRACTORS

The Salem Generating Station was designed and constructed by Public Service Electric & Gas (PSE&G). Westinghouse Electric Corporation designed and furnished the nuclear steam supply equipment and systems including the fuel assemblies.

PSE&G contracted United Engineers and Constructors Inc. of Philadelphia, Pennsylvania, to supervise field erection. PSE&G also engaged several consultants to provide technical assistance in various areas. These consultants are listed below.

Consultant	Program
Southwest Research Institute, San Antonio, Texas	Quality Control
S. M. Stoller Corporation, New York, New York	Reactor Core and Nuclear Fuel Cycle
Smith - Singer Meteorologists, Inc., (Now Meteorological Evaluation Systems, Inc.) Amityville, Long Island, New York	Meteorology
Dames and Moore, Cranford, New Jersey	Geology, Hydrology, Seismology
Pritchard - Carpenter, Consultants, Coral Gables, Florida	Hydrology
Radiation Management Corporation, Philadelphia, Pennsylvania	Radiation Monitoring, Emergency Planning
Ichthyological Associates, Middletown, Delaware	Marine Ecology

Porter-Gertz, Consultants, Inc., (Now Porter Consultants) Ardmore, Pennsylvania	Radiation Monitoring, Emergency Planning
Framatome Technologies, Inc., (FTI) of Lynchburg, Va. and Raytheon Corp.	Unit 1 Steam Generator changeout

During the operational phase, various consultants and contractors have been employed to support station operation. These organizations are selected and perform the applicable service in accordance with the Salem QA Manual.

The meteorological data collection system hardware is listed in Table 2.3-16. A sigma computer is installed for experimental purposes, but data from it is not used by any part of the system.

All parameters on the primary tower are recorded on strip charts in the Meteorological Instrument Building at the base of the tower. Wind speed and direction at Elevations 300 feet and 33 feet, ambient temperature (33 feet) and delta temperatures ($T_{300} - T_{33}$) and ($T_{150} - T_{33}$) are also recorded in the SGS Unit 1 Control Room. Data from the backup tower is not recorded on strip charts.

The data acquisition system includes capabilities for remote interrogation in addition to data acquisition. The data acquisition systems consist of primary and backup data acquisition systems (DAS) located at the primary tower and in the Salem TSC, respectively. A diagram of the system configuration is provided on Figure 2.3-8. A list of the system hardware components is tabulated in Table 2.3-16A. The rain gauge uses a tipping bucket, which meets the NRC criteria of measuring 0.01 inch of precipitation.

The primary and backup DAS are configured with identical hardware. Each DAS consists of a Hewlett-Packard 9826A Computer, 3497A Data Acquisition / Control Unit, and a Dames & Moore transient protection system. Each DAS is provided with three communication ports, one as a link to the Hope Creek Engineering Data Base System (EDBS), one as a spare, and one for direct dial-up capability. Each DAS provides for up to 7 days of 15-minute averages.

The primary DAS collects data from the meteorological parameters listed in Table 2.3-16. The backup DAS collects wind speed and direction from the three tower elevation and two delta temperatures, as well as the backup meteorological tower. The data acquisition system calculates a sigma theta for each of the three level wind directions.

Digital averages of the primary and backup system wind speed and wind direction are calculated using a two second sampling period,

averaged over 15 minutes. The sampling period for delta temperature is two seconds. Ambient temperature, dew point, barometric pressure, and precipitation are sampled on a 30 second interval for the calculation of the 15 minute average.

The calculations of the sigma thetas on the primary backup system use the two second samples of horizontal wind speed and direction at each elevation/location. The use of two samples over a 15 minute averaging period provides 450 samples. The number of instantaneous values used to calculate sigma theta exceeds the minimal value of 180, referenced in proposed Revision 1 to USNRC Regulatory Guide 1.23, by a factor of 2.5.

Data interrogation is possible through dial-up connection to the digital data acquisition systems, which also provide data to the Hope Creek Engineering Data Base System. The EDBS supports display units in the EOF, the Salem and Hope Creek Control Points, the Salem and Hope Creek TSC's, the Salem and Hope Creek OSC's, the Salem Unit 1 Control Room, and other locations through dial up modems.

Additional sources of meteorological data to provide a description of airflow trajectories from the site out to a distance of 50 miles include Wilmington and Philadelphia National Weather Service (NWS) stations.

Hourly wind, temperature, and cloud cover data are readily available from these NWS stations. Pasquill-Gifford stability can be derived from the wind speed and cloud cover data using an algorithm from the Environmental Protection Agency CRSTER air quality model.

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2.3.4 Short-Term Diffusion Estimate

2.3.4.1 Objective

The objective is to provide conservative and realistic short term estimates of relative concentration (X/Q), at both the site boundary and the outer boundary of the low population zone (LPZ) following a hypothetical release of radioactivity from SGS Units 1 or 2. The assessment is based on the results of atmospheric diffusion modeling and onsite meteorological data.

A ground-level accidental radionuclide release from SGS is analyzed at various distances. Conservative and realistic X/Q values at the exclusion area boundary (EAB) are derived for the 0- to 2-hour period following a postulated accident. Conservative and realistic estimates of the X/Q value at the outer boundary of the LPZ are computed for 2, 8, 16, 72, and 624 hours following a postulated accident. For this modeling assessment, the EAB is a distance of 1270 meters in all sectors except the Northeast and East, which were 1391 meters. The LPZ boundary is 5.0 miles (8,047 meters), all sectors.

2.3.4.2 Accident Assessment

The short-term, 0- to 2-hour X/Q values for ground-level releases are calculated with the sector dependent model described in Regulatory Guide 1.145, Reference 8. Annual accident X/Q values are also required to derive the intermediate time period X/Q values. These annual accident X/Q values are derived using the long-term diffusion model described in Regulatory Guide 1.111, Revision 1, Reference 9.

2.3.4.2.1 Methodology

The procedures used to estimate the X/Q values for the appropriate time periods following a postulated accident are described in Regulatory Guide 1.145. The diffusion model generates a cumulative frequency distribution of X/Q values for each sector-distance combination representing the first 2 hours after the postulated accident. These 2-hour X/Q values are based on 1-hour averaged data, but are assumed to apply for 2 hours. The frequency distributions are plotted on a log-probability scale for each sector-distance combination, and are then enveloped in accordance with the methodology described by Markee and Levine in Reference 11.

The X/Q value that is equaled or exceeded 0.5% of the time at each sector-distance combination is then determined from the intersection of the envelope and the 0.5% probability level. The highest sector dependent X/Q value is then compared with the "overall" 5% accident X/Q value. The highest value represents the conservative 2-hour accident X/Q. The realistic 2-hour accident X/Q is evaluated at the overall 50% probability level.

The overall 5% and 50% X/Q values are determined by summing the sixteen sector dependent X/Q distributions for each distance into a cumulative frequency distribution representing all sectors and again enveloping the data points. The 5% and 50% values are determined by the intersection of the envelope with the 5% and 50% probability levels, respectively.

APPENDIX 2.3A

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DC Power Supply System

Power distribution lines to equipment required for emergency transformers and switchgear supplying the Engineered Safety Features

Control Boards

Motor Control Centers

13. Control equipment, facilities and lines as required for the preceding items

14. Containment Polar Crane

15. Auxiliary Feedwater and Service Water Systems (portions)

16. Sampling System Piping (to outermost containment isolation valve)

17. Main Steam System (to isolation valve)

18. Feedwater System (to outermost containment isolation valve)

19. Combustible Gas Control System (partial)

20. Fuel Handling System

21. Instrumentation and Control Systems required for safe shutdown, including safety-related instrumentation

22. Electrical Cable Tunnels

23. Spent fuel pool cooling and purification system piping (SFPC components have been seismicly evaluated under SQUG GIP methodology).

QA program controls as identified in Section 17.2 are applied, but not limited to, the above Class I systems, structures, and components

Class II

The following list establishes a general category of Class II items:

1. Pressurizer Relief Tank
2. Sampling System (partial)
3. (This text has been deleted)
4. Holdup Tank Transfer Pumps
5. Evaporator
6. Evaporator Condensate Demineralizers
7. Waste Monitor Tanks
8. Waste Monitor Tank Pumps
9. Primary Water Storage Tanks
10. Concentrates Holdup Tank
11. Waste Gas Disposal System

Class III

The following list establishes a general category of Class III items:

1. Turbine Generator Area Structure
2. Buildings containing conventional facilities
3. Waste Disposal System (partial)

4. Chemical Mixing Tank

5. Resin Fill Tank

6. Demineralized Water Storage Tanks

7. Conventional equipment, tanks, and piping other than Classes I and II

3.2.1.3 Seismic Criteria

For Class I (seismic) equipment, dynamic methods or conservative static equivalents were used to determine that components and structures will operate or maintain their integrity, as required. For Class II (seismic) equipment, static methods were used and Class III (sesimic) equipment meets applicable codes.

3.2.2 System Quality Considerations

3.2.2.1 Codes and Standards

The codes and standards applied in the design of plant systems are described in the section of the FSAR containing the respective system description.

3.2.2.2 ANSI B31.7

ANSI B31.7 was used for piping design wherever possible. Where not possible to comply with ANSI B31.7, the requirements of ASME III - 1971 were adhered to.

The major deviations from ANSI B31.7 requirements involve radiographic inspection technique. The original edition of B31.7 was deficient in this area as evidenced by the need for ANSI B31 Code Case 72. The ANSI committee recognized that the radiographic requirements of B31.7 were not suitable for field radiography of thin walls and small diameter piping butt welds. The

incorporation of Code Case 72, without change, into the 1971 edition of Section III of the ASME Boiler and Pressure Vessel Code and its retention up to the present edition demonstrates that it provides a realistic approach to field radiography.

In addition, radiographs of Nuclear Class 3 cement lined pipe were difficult to interpret. The 1970 addenda to B31.7 allowed 100 percent magnetic particle inspection in lieu of random radiography. This provision was also incorporated into Section III, 1971 Edition. The Service Water System contains Nuclear Class 3 cement lined pipe for which this alternate inspection method was utilized. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

The use of a later code was restricted to inspection and did not involve any requirements from Section III such as materials, stress calculations, etc, that would modify our original design. Consequently, other requirements from a later Code would not be applicable. Therefore, the integrity of field welds has not been compromised and Public Service Electric and Gas has complied with the commitment to use ANSI B31.7 wherever possible.

3.2.2.3 Field - Run Piping

Field running of small diameter piping, i.e., complete assembly at the erection point without reference to design drawings, is not permitted for essential systems. Therefore, no special quality assurance measures or performance tests are required.

2. Unit 2

The Unit 2 LP turbine is a double flow design consisting of three elements. The original LP turbine rotors were of the built-up type consisting of individual discs shrunk on and keyed to a shaft. To optimize thermal performance and provide long term reliability, the turbine has been retrofitted with a monoblock rotor forging with fully integral discs and couplings. This design incorporates blading with integral shrouds. The last stage rotating blade length is 47", resulting in a large annulus area. Figure 3.5-6A depicts the LP turbine.

Steam will enter the LP turbine inlet at the cross-over pipe tee connection. Inlet flow guides will direct the steam in both directions of this double flow element.

There are nine stages of controlled reaction blading. The first four stages on each end are housed in the first blade ring. The next two stages on each end are housed in the second blade ring. Both blade rings on each end are separately supported and made from stainless steel to minimize erosion/corrosion concerns. The last three stages on each end are of segmental assembly construction that are caulked into the inner cylinder.

Advanced techniques were used to design the one-piece inner cylinder, resulting in minimized steam leakage and structural streamlining which minimizes blade path differential thermal expansion. The entire outer casing is subjected to low temperature exhaust steam.

The outer and inner cylinders are fabricated mainly of ASTM 515-GR65 material. The minimum specified properties are as follows:

Tensile Strength, psi, min.	65,000
Yield Strength, psi, min.	35,000
Elongation in 8 in., percent, min.	19
Elongation in 2 in., percent, min.	23

The LP rotors are made of 3.5 NiCrMoV alloy steel. The specified minimum mechanical properties are as follows:

Tensile Strength, psi, min.	115,000
Yield Strength, psi, min.	100,000
Elongation in 2 in., percent, min.	17
Reduction of Area, percent, min.	50
Impact Strength, Charpy V-Notch, ft-lb, min. at room temp.	120
50% fracture Appearance Transition Temp. □F, max.	35

The first five rotating stages of the Ruggedized rotors use a one-piece integral shroud blade. The first three rows are made of 12% Cr material. The next two are made of 17-4 PH stainless steel material. The last three rows of the rotors use shot peened profiled free-standing blades also made of 17-4 PH stainless steel.

3.5.4.1.3 Overspeed Protection System Testing

The turbine overspeed protection system is tested by accelerating the turbine from 1800 rpm until it trips. Should the turbine fail to trip automatically, it is manually tripped prior to exceeding 12 percent overspeed. The turbine stop and governor valves are tested by actually cycling the valves. For Salem Units 1 & 2, the Turbine Overspeed Protection requirements are discussed in Section 10.2.2.6, "Turbine Overspeed Protection".

3.5.4.2 Probability of Missile Generation

Present manufacturing and inspection techniques for turbine rotor and disc forgings make the possibility of an undetected flaw and subsequent catastrophic structural failure extremely remote. Forgings are subject to inspection and testing both at the forging suppliers and at Westinghouse. Current design procedures are well established and conservative, and analytical tools such as finite element and fracture mechanics techniques allow in depth analysis of any potential trouble spots such as areas of stress concentration or inclusions which could give rise to crack propagation.

Westinghouse has submitted to the Nuclear Regulatory Commission for review, a memorandum and topical reports (References 1 - 3 and 5) related to the turbine missile issue as part of their program to reduce the turbine missile risk.

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

3.6.1 Systems In Which Design Basis Piping Breaks Occur

Design basis piping breaks are postulated to occur in the following systems:

1. Reactor Coolant Loop
2. Pressurizer Surge Line
3. Main Steam System
4. Feedwater System
5. CVC Letdown Line
6. Steam Generator Blowdown Line
7. Steam Supply to Auxiliary FW Pump Turbine
8. CVC Charging and RC Pump Seal Injection (Unit 2 Only)
9. Heating Steam (Unit 2 Only)
10. Heating Water (Unit 2 Only)

3.6.2 Design Basis Piping Break Criteria

The criteria for postulating design basis piping breaks are discussed for each system in Sections 3.6.4 and 3.6.5 where the analysis and protection of the various systems are presented.

3.6.2.1 Criteria for Determination of Location and Orientation of Postulated Breaks Inside Containment - Unit 1 Main Steam, Main Feedwater, and Steam Generator Blowdown

Salem Unit 1 was designed and constructed in the time frame of September, 1968 through August, 1976. The NRC's Giambusso letter, issued in 1972, imposed HELB

criteria on systems outside containment after the plant had already been designed, and major rework was required to meet these new (and changing) criteria. The guidance and criteria noted are those that evolved over time. The Main Steam (MS) and the Main Feedwater (MFW) high energy line breaks (HELBs) discussed in UFSAR Section 3.6 are explicit for breaks outside containment, but rather general for breaks inside containment. Given the above background information, explicit Salem Unit 1 design and licensing criteria for HELBs inside containment were determined, including the Steam Generator Blowdown (SGBD) lines. Based on this information, the criteria used for Salem Unit 1 MS, MFW, and SGBD HELBs inside containment are given below.

The current NRC guidance for HELBs is provided in Generic Letter 87-11 and in the latest revision to BTP MEB 3-1, attached to that Generic Letter. During the Steam Generator Replacement Project (SGRP) which replaced the original Westinghouse Model 51 steam generators (SGs) with Model F SGs, the current NRC guidance was used to postulate breaks inside containment for the portions of piping modified by the SGRP. As evidenced by Generic Letter 87-11 and as noted in the "Background" discussions in MEB 3-1, the latest NRC positions are intended to utilize the available piping design information by postulating pipe ruptures at locations having relatively higher potential for failure, such that an adequate and practical level of protection may be achieved. The current HELB design of the MS, MFW, and SGBD piping and the criteria used for HELBs inside containment are given below. These Positions provide the current design and licensing basis for the Salem Unit 1 MS, MFW, and SGBD lines inside containment replaced or modified by the SGRP. Note that any corresponding conformance to the BTP MEB 3-1 Sections related to pipe breaks/cracks does not constitute a commitment to conform to all the positions of the Branch Technical Position.

Position I: Types of Breaks to be Assumed in High-Energy Piping

1) Circumferential breaks are postulated in piping exceeding a nominal pipe size of 1 inch. This conforms to BTP MEB 3-1, Section B.3.a(1).Refer to Positions III and IV.

2) Longitudinal (slot) breaks are postulated in piping 4 inches nominal pipe size and larger. This conforms to BTP MEB 3-1, Section B.3.b(1). Also see Position V.

3) Leakage cracks are postulated in piping exceeding a nominal pipe size of 1 inch. This conforms to BTP MEB 3-1, Section B.3.c(1). Refer to Position VII.

Position II: Main Steam Piping Stress Reconciliation

A reconciliation, of the differences between the original design of the MS piping system and the as-designed for contruction configuration, has been prepared in accordance with NCIG-05, Revision 1 (Guidelines for Piping System Reconciliation). Based on this reconciliation, there is no new break postulated for the MS lines inside containment. Based on these evaluations, it is concluded that no changes are required to any of the existing *in-situ* protective features provided for protection from a MS pipe break inside containment.

Position III: Circumferential Breaks at SG Nozzle (for longitudinal breaks, see Position V)

Circumferential breaks are postulated at the steam generator nozzle for the MS, MFW, and SGBD (i.e., blowdown and drain) piping modified by the SGRP. This conforms to BTP MEB 3-1, Section B.1.c(2)(a). Also see the discussions in Position VI.

Position IV: Circumferential Breaks at Locations Where the Stresses Exceed $0.8\ (S_h + S_a)$ (for longitudinal breaks see Position V)

1) Circumferential breaks are postulated to occur at locations where the stresses exceed $0.8\ (S_h + S_a)$. This corresponds to BTP MEB 3-1, Section B.1.c(2)(b)(ii).

2) The stresses in the modified MFW/SGBD lines inside containment have been confirmed and documented to be below the 0.8 criterion. A reconciliation of the MS line inside containment (see Position II) has verified that the stresses are below the 0.8 criterion. Therefore, circumferential breaks in the MS, MFW, and SGBD lines (except at the SG nozzles) are not postulated to occur. Thus there are no MS, MFW, or SGBD intermediate breaks postulated, based on the 0.8 stress criterion.

3) Based on the NRC Generic Letter 87-11, additional arbitrary (non-stress based) intermediate pipe breaks are NOT postulated to occur in any of the high-energy piping (MS, MFW, SGBD).

Position V: Longitudinal (Slot) Breaks

1) Longitudinal (slot) breaks in the SGBD piping are not assumed to occur, since this piping is less than 4 inches nominal pipe size. This is consistent with Position I and with BTP MEB 3-1, Section B.3.b(1).

2) Longitudinal breaks in the MS and MFW piping are not assumed to occur at the terminal ends, consistent with BTP MEB 3-1, Section B.3.b(2).

3) Other longitudinal breaks in the MS or the MFW piping are not assumed to occur, except where other circumferential breaks are assumed. This is consistent with BTP MEB 3-1, Section B.3.b, which states that:

> "The following longitudinal breaks should be postulated in high-energy fluid system piping at the locations of the circumferential breaks specified in B.3.a...."

(BTP MEB 3-1, Section B.3.a discusses locations of circumferential breaks. The circumferential break locations for Salem Unit 1 MS, MFW, and SGBD are those discussed in Positions III and IV, above. Since MS and MFW circumferential breaks are only required to be postulated at the steam generator nozzles, this removes longitudinal breaks from further consideration, and is consistent with NRC BTP MEB 3-1.)

Position VI: Containment Penetrations

1) MS line inside containment: The MS piping modified by the SGRP is provided as a like-for-like modification in form, fit and function. The SGRP MS piping modification does not affect the existing *in-situ* provisions at the MS containment penetration.

2) MFW line inside containment: The containment penetration calculations were revised considering pipe loads from the revised stress analysis calculations affected by the SGRP, as applicable. A re-analysis of the stresses for MFW demonstrates that stresses at the containment penetration anchor point inside containment do not exceed 0.25 $(S_h + S_a)$.

3) SGBD line inside containment: A seismic anchor point is located in the existing piping between the modified blowdown piping and the containment penetration. Thus the SGRP SGBD line modification does not affect the existing stress analysis for the containment penetration.

Position VII: Leakage ("Critical") Cracks

1) Leakage cracks are postulated at axial locations where the calculated stresses exceed 0.4 $(S_h + S_a)$. This is consistent with NRC BTP MEB 3-1, Section B.1.e(2). (Note that Equations (9) and (10) of NC/ND-3653 are equivalent to Equations 12a and 13a of ANSI B31.1, 1977 Edition.)

2) The fluid flow from a leakage crack is based on a circular opening of area equal to that of a rectangle one-half pipe diameter (OD) in length and one-half pipe wall thickness in width. This conforms to BTP MEB 3-1, Section B.3.c(3).

3) Leakage cracks are not postulated to occur in the MS piping modified by the SGRP, since a reconciliation of the portion of the MS line inside containment modified by the SGRP has verified that the stresses are below the 0.4 criterion. For the rest of the MS piping inside containment (see Position II), the SGRP did not modify the adequacy of the *in-situ* design features previously provided.

4) The effects of leakage cracks in the MFW piping installed by the SGRP, where the stresses exceed 0.4 $(S_h + S_a)$, have been evaluated and the appropriate mitigating features have been provided, where required.

5) The effects of leakage cracks of the SGBD piping installed by the SGRP, where the stresses exceed 0.4 $(S_h + S_a)$, have been evaluated and the appropriate mitigating features have been provided, where required.

3.6.3 Design Loading Combination

Loadings on protective structures, pipe whip restraints, and other components subsequent to a postulated piping break include pipe reaction, pipe whip, jet impingement, pressurization of compartments, water flooding, and steam flooding. They are combined directly as appropriate for each case. Their combination with other loadings generally categorized as faulted condition are included in other appropriate sections in this report; for instance, for Class 2 and 3 components, in Section 3.9.2; and for Class 1 components in Section 5.2.

3.6.4 Dynamic Analysis

Dynamic analyses of the Reactor Coolant System (RCS) and other high energy fluid systems are described below. What follows is a description of the original design basis dynamic analyses performed for Salem Units 1 & 2. The replacement of the Unit 1 steam generators necessitated reanalysis of the Unit 1 RCS. This reanalysis is described in Appendix 3B.

3.6.4.1 Reactor Coolant Loop System Analysis

A mathematical model is made for the RCS piping and primary equipment. This model describes the spatial geometry, lumped mass locations, and other node points. The stiffness characteristics of the equipment support structures are incorporated in the model as elastic restraints. A computer program computes normal mode characteristics, forces, deflections, and stresses. For hydraulic blowdown analysis, the entire primary system is represented by a two loop RCS hydraulic model consisting of one broken and one unbroken loop. This model is used to define the space-time dependent hydraulic forcing functions generated by the fluid in the primary coolant loops and reactor pressure vessel during a design basis loss-of-coolant accident (LOCA). For the broken loop, a circumferential break in the hot leg and cold leg is considered. Pipe whip restraints in the crossover legs (thrust blocks) are included in the design to prevent gross motion of the RCS piping; hence, not permitting impingement of adjacent piping supports, etc.

All sample lines have normally closed valves, located inside the missile barrier. Whipping could result if a rupture occurred between the reactor coolant loop and the closed valves. The size of the sample lines and the pipe routing are such that subsequent damage to other piping would not occur even if whipping occurred.

Equipment located inside the containment which is required for operation during a LOCA, such as the containment spray piping, containment isolation valves, containment fan cooling units, essential electrical cables and instrumentation are all located between the missile barriers.

3.6.5.1.3 Restraint

Where physical arrangement and barriers were ascertained to be impractical and/or to offer insufficient protection, physical restraint of piping was provided on reactor coolant, main steam, and feedwater lines.

Circumferential and longitudinal ruptures of the reactor coolant loop and pressurizer surge line have been postulated at points of change in direction, and restraint has been provided to prevent pipe whip from occurring (see Figure 3.6-7). The reactor vessel and steam generator supports have been designed to prevent an initial rupture of a reactor coolant loop from causing the failure of another reactor coolant loop, or a steam or feedwater line. Also the steam generator support system prevents a reactor coolant hot leg rupture from causing the failure of the cold leg and vice-versa as well as a steam or feedwater rupture from damaging a reactor coolant line. All lines connected to the reactor coolant loop, which penetrate the containment wall have been anchored to the crane wall. Each anchor has been designed to be stronger than the pipe. Should a reactor coolant loop rupture occur, the resulting jet force will therefore not be transferred to the containment wall through any branch lines.

The charging and letdown lines are normally opened to the reactor and their rupture could result in whipping within a loop compartment. The lines are small, however, and therefore unable to damage the large reactor coolant lines. Both lines are anchored to the missile barrier to prevent containment damage from RCS break forces being transferred through the charging or letdown lines.

Safety injection piping which penetrates the containment has either been anchored at the missile barrier wall to prevent a reactor coolant loop rupture from breaching the containment through the safety injection line or has been routed to assure that loop rupture forces cannot transfer sufficient loads back to the containment wall through the safety injection line to cause a breach.

All RHR lines penetrating the missile barrier have been anchored to the missile barrier wall to prevent reactor coolant pipe rupture forces from being transferred to the containment through the RHR branches.

The portions of the steam and feedwater lines not routed within barriers are restrained to prevent pipe whip. Main steam and feedwater lines have been anchored at and restrained outside the containment so that rupture will not affect containment integrity. (See Figures 3.6-8, 3.6-9, and 3.6-10.)

3.6.5.1.4 Protective Measures Evaluated for Salem Unit 1 Main Steam, Main Feedwater, and Steam Generator Blowdown as a Result of the Steam Generator Replacement Project

1) A deficiency has been resolved to include the effects of the MS terminal end break at the steam generator nozzle on the MS/MFW pipe whip restraint structure.

2) A MFW pipe whip restraint has been designed, analyzed, and provided to mitigate a circumferential rupture of the MFW line at the steam generator nozzle, including the effects of the jet impingement on the MFW pipe whip restraint.

3) The effects of a circumferential rupture of the MFW line at the steam generator nozzle have been evaluated, and the MS/MFW pipe whip restraint structure has been modified to mitigate this break.

4) The SGBD line has been evaluated to assure that, for a circumferential rupture of the SGBD line at the steam generator nozzle, an unrestrained SGBD line does not affect the safe shutdown capability of the unit for that scenario, assuming a loss of offsite power.

3.6.5.2 Main Steam System

The Main Steam System is illustrated on Figures 10.3-1A and B and is described in Section 10.3. The piping arrangement is shown on Figures 3.6-10 through 3.6-13. Each of the four 30-inch OD x 1.007-inch wall main steam pipes runs from the nozzle on its respective steam generator inside the containment (Elevation 172 feet) vertically downward and then out of the containment through a separate penetration which also forms an anchor point in the system (Elevation 108 feet). A 16-inch ID flow restrictor is located in the vertical run of each main steam line inside the containment at Elevation 135 feet. Two steam lines penetrate the containment and enter an enclosed penetration on the north side of the containment, while the two remaining steam lines penetrate the containment into an enclosed penetration area on the south side. Each steam line then changes to 32-inch OD x 1.5-inch wall thickness and is routed toward the turbine in a horizontal run. This horizontal section within each penetration area contains the 34-inch OD x 3.314-inch thick safety valve manifold and the 24-inch ID main steam isolation valves (MSIVs).

Downstream of the MSIVs, the steam lines were originally designed to return to 32-inch OD x 1.073-inch wall thickness, run vertically to Elevation 125 feet or 13 feet, exit the penetration through wall sleeves, and run horizontally to the mixing bottle, the four steam lines are manifolded to two pipes which then run to the high pressure turbine.

The Main Steam System has been conservatively designed in order to provide the ultimate in reliability of operation under normal conditions and improbability of failure under abnormal conditions. The piping, as originally designed, has been manufactured with a conservative wall thickness of 2.11 inches inside the penetration wall sleeve, 1.50 inches from the sleeve to the main steam safety valve manifold and 3.314 inches at the safety valve manifold, even though the code required wall thickness is less than 1 inch. This extra wall thickness serves the dual purpose of eliminating any "high stress" areas at the penetration anchor (thus making the anchor point no more likely to fail than any other portion of the line) and providing added assurance of preservation of containment integrity and main steam isolability. To further assure isolability, maintenance of containment integrity and continued shutdown capability, an extensive network of steel limit stop columns and supports has been provided in the penetration area. This steel has been designed to withstand the fluid dynamic forces

associated with the postulated pipe breaks and thus prevents the imposition of excessive strains upon the piping upstream of the MSIVs or upon the containment pressure boundary as a result of such breaks.

Mechanical restraints have been installed at, and adjacent to, the MSIVs due to their criticality and proximity to the containment. Several types of restraints have been used, each serving a distinct function. As shown on Figure 3.6-9, restraints are provided on the steam lines adjacent to the MSIVs. These restraints serve to limit pipe motion following a postulated rupture such that neither excessive moments nor physical impact can damage the containment, containment penetrations, or MSIVs. Supports are provided on the valve body to aid in supporting valve weight and supply restraint against undesired motion. Where necessary, the valve operator has also been restrained to limit seismically induced motions.

The entire Main Steam Piping System outside the containment has been designed in accordance with the ANSI B31.1, Code for Pressure Piping Power Piping. The piping was purchased in accordance with ASTM Specification A155 Grade KC70 Class I, A155 Grade KCF70 Class I, AI06 Grade B, A106 Grade C, or substitutable chrome alloy, or stainless steel material depending upon the specific piece in question. The ASTM A155 piping was subjected to supplementary tests S1 (check analysis on each length of pipe), S2 (Tension and Bend Tests), S3 (Hardness Tests), and S4 (Magnetic Particle Examination) in addition to the 100 percent ultrasonic examination of the unformed plate required by the base ASTM Plate Specification. The ASTM A106 piping was subjected to supplementary tests S2 (check analysis on each length of pipe), S4 (flattening test on each length of pipe), and S5 and S6 (etching test on each length of pipe). Radiographic examination has been performed on joints in piping of 3/4-inch wall thickness and over, and nozzle welds were subjected to magnetic particle examination. Welded joints in the main header downstream of the MSIVs and welded joints in all main steam piping upstream of the MSIVs were made utilizing the gas tungsten

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The forcing function used for design of restraints was assumed to be a step function of magnitude 1.26 PA, where P is the initial pressure in the pipe (conservatively assumed to be hot standby pressure) and A is the cross sectional flow area of the ruptured pipe. The 1.26 thrust factor is theoretically derivable from ideal gas laws, its conservatism is assured in that the Moody correlation predicts a saturated steam thrust factor closer to 1.20. Dynamic load factors were used where applicable to account for energy loadings in the static analysis of structural components.

In addition, the main steam (MS) lines of Salem 1 steam generators are subjected to postulated guillotine breaks. The pipe break points are near nozzle weld sections. The time history analysis is performed to determine the pipe whip restraint reaction forces and the pipe line displacements, especially the break point movements of the MS line.

The pipe lines from the nozzle break points to the wall anchorage points are modeled with plastic pipe and elbow elements. The pipe whip restraints are modeled with springs. Each directional restraint gap is considered. Pipe tie rods are modeled as slacks. The gap-spring combination element is used for the restraints. Pipe break force time histories are used for the break points and elbow tangent points. Unit area thick plates are used to carry the follower loads. The beam elements under the thick plates are used to stabilize the plates. All of the plates and beams have no masses. The fontal solver of ANSYS Version 5.2 is used for dynamic analysis. The pipe line and its restraints are properly modeled in the finite element mode. Damping coefficients are considered proportional to the mass and stiffness. Seven (7) percent of critical damping is used for frequencies of 10 Hz and 100 Hz. The damping is lower between these frequencies and higher for other frequencies. The restraints had no damping associated with stiffness. The restraints are considered to have no masses, hence no damping is associated with masses either. Complete restraint condition is applied to the anchorage sleeve for the cut-off point boundary conditions. The analysis results are time history plots and listings of designated response items. The extreme response values and time are also determined.

The following items are both important to safety and are located near the postulated break locations in the main steam and feedwater lines:

1. The Auxiliary Building wall adjacent to the Control Room.
2. The Containment Building wall.
3. The penetration area roof beneath the steam lines.

flattening test of one length of each pipe lot was required. For sections of this piping which are 8 inches nominal size and larger, supplementary etching tests were required. Welded joints in main headers were made using the consumable insert tungsten inert gas first pass technique. Welded joints for piping replaced under the Steam Generator Replacement Project were made using the open root, manual gas tungsten arc process for the root pass, and the automatic gas tungsten arc process for the balance of the weld. Radiographic examination has been performed on welded joints in piping of 3/4-inch wall thickness and over, and nozzle welds have been subjected to magnetic particle examination. Additionally, piping from the steam generator inlet feedwater control valves to the feedwater isolation valves has been constructed in accordance with Section I of the ASME Boiler and Pressure Vessel Code, and piping from the feedwater isolation valves to the steam generators has been constructed in accordance with the materials, fabrication, fabrication inspection, and quality control requirements of ANSI B31.7 for Nuclear Class 1 piping.

To eliminate potential cracking and erosion corrosion concerns in the Unit 1 steam generator inlet feedwater piping, steam generator feedwater nozzle-piping transition forging pieces have been installed. The material for these forgings was purchased in accordance with ASME Section II, Part A, Specification SA-508, Class 2 quenched and tempered low alloy forging material. This forging material meets all ASME Section III, Class 1 fracture toughness requirements. Although installed in feedwater piping classified as Class 2 piping, these forging pieces are fabricated, inspected and installed to Nuclear Class 1 requirements. Additionally, these transition forging pieces are analyzed to meet the stress limits and requirements for cyclic operation of the ASME Code Section III, Sub-article NB-3200, for Class 1 piping.

3.6.5.3.1 Criteria for Determination of Location and Orientation of Postulated Break

The Reference 1 criteria are not totally applicable to the feedwater piping for the same reasons discussed in Section 3.6.5.2.1 for the main steam piping.

In order to provide a degree of protection equivalent to the recommended Reference 1 criteria, however, the following were implemented:

1. The wall thickness of the feedwater piping within the penetration areas and in the portion that runs adjacent to the Auxiliary Building (Control Room) wall were increased to Schedule 120.

2. Stress in the feedwater piping runs described in (1) above was limited to 0.25 (S_h + S_a) for the normal operational plus OBE (1/2 SSE) loading cases.

3. Circumferential and longitudinal breaks were postulated at high stress locations in the feedwater line (points C, D, and F on Figure 3.6-10).

4. Critical cracks (as defined in Reference 1) were postulated in the feedwater line both inside and outside the penetration areas.

3.6.5.3.2 Analysis of Postulated Pipe Breaks

As stated in Section 3.6.5.3.1 feedwater piping breaks were postulated at points C, D, and F on Figure 3.6-10 in both the longitudinal and circumferential directions. The forcing function for design of restraints was assumed to be a step function of magnitude 2.0 PA, where P and A are as defined in Section 3.6.5.2.2. The 2.0 thrust factor is theoretically derivable for nonflashing liquids, and is known to be conservative for saturated and slightly subcooled liquids, whose thrust factor is closer to 1.20. Dynamic load factors were used where applicable.

The consequences of feedwater pipe breaks are identical to those presented for steam line breaks in Section 3.6.5.2.2. Pipe whip restraints similar to those provided for the main steam lines were provided for the feedwater piping to prevent damage to the Auxiliary Building and penetration area walls discussed in Section 3.6.5.2.2. These restraints are shown on Figure 3.6-19. The discussion presented in Section 3.6.5.2.2 regarding the design of the restraints, fluid impingement effects, containment impact, and penetration integrity is also applicable to the postulated feedwater line breaks.

In addition, the Feedwater (FW) lines of Salem 1 steam generators are subjected to postulated guillotine pipe breaks. The pipe break points are near nozzle weld sections. The time history analysis similar to that described in Section 3.6.5.2.2 for the main steam line breaks is performed to determine the pipe whip restraint reaction forces and the pipe line displacements.

3.6.5.3.3 Effects of Postulated Breaks on Safety-Related Equipment

The discussion presented in Section 3.6.5.2.3 also applies to the Steam Generator Feedwater System.

coolant from the regenerative heat exchanger inside the containment through a containment penetration in the Elevation 78 foot piping penetration area. The pipe runs across the penetration area into the Elevation 84 foot pipe alley, where it bifurcates. One branch goes to normally closed valve 1CV8 in the safety injection pump room, while the other branch runs along the pipe alley wall until it turns into the letdown heat exchanger room. After it exits the letdown heat exchanger, it is no longer considered to be a high energy line.

The letdown line is constructed to Nuclear Class 2, Seismic Class II standards, from ASTM-A312 TP 304 stainless steel pipe. Postulated break locations have been sleeved and restrained in accordance with the design criteria of Section 3.6.5.11. The section of piping located in the safety injection pump room has been totally encapsulated, as shown on Figure 3.6-21. The pipe alley and letdown heat exchanger room are fitted with watertight steel doors to contain the energy released by a postulated break. The letdown heat exchanger room is vented through the normal exhaust ducting. The pipe alley is vented to the mechanical penetration area and then through a vent penthouse to the atmosphere. With these modifications, postulated ruptures of this piping will have no detrimental effect on plant shutdown capability or safety systems.

Emergency procedures in the event of rupture of this line consist of (a) identification of the break, and (b) remote manual isolation of the line.

3.6.5.5 Steam Generator Blowdown System

The Steam Generator Blowdown System is described in Section 10.4 and is shown on Figures 10.4-18A and B. The piping arrangement is shown on Figures 3.6-22 and 3.6-23. The steam generator blowdown piping which is encompassed by the definition of high energy lines contains 814 psig (Unit 1) and 790 psig (Unit 2) saturated water from the secondary side of the steam generators. The four 3-inch pipes, one from each steam generator, penetrate the containment wall into the Elevation 78 foot piping penetration area, then run immediately upward into the Elevation 100 foot piping penetration area. Here, each of the lines bifurcates with one branch of each line going to each of the No. 11 and 12 steam generator blowdown tanks.

The steam generator blowdown lines are constructed to Nuclear Class 2, Seismic Class I standards upstream of the containment isolation valves, and nonnuclear, Seismic Class III standards downstream of the isolation valves. Postulated break locations have been restrained to prevent pipe whip damage to vital equipment. With these modifications, postulated ruptures will have no detrimental effect on plant shutdown capability or safety systems.

Emergency procedures in the event of a rupture of these lines consist of (a) identification of the break, and (b) remote manual isolation of the line.

3.6.5.6 Steam Supply To The Auxiliary Feedwater Pump Turbine

The steam lines to the auxiliary feedwater pump turbine are described in Section 10.3 and shown on Figures 10.3-1A and B. An isometric view of the piping is shown on Figure 3.6-24. The two pipes carry 814 psig (Unit 1) and 790 psig (Unit 2) saturated main steam from the main steam lines in the Elevation 100 foot piping penetration area along the Auxiliary Building wall, joining together into one line before entering the Auxiliary Building. The steam line enters the Auxiliary Building in the waste evaporator room on Elevation 100 foot. It then passes down into the pipe alley and enters the auxiliary feedwater pump turbine room on Elevation 84 feet.

The steam lines are constructed to Nuclear Class 2, Seismic Class I standards from ASTM-A106 Grade B carbon steel pipe or substitutable chrome alloy or stainless steel material. The piping was subjected to Supplementary S2 (check analysis), S4 (flattening test on each length of pipe), and S5 - S6 (etching test on each length of pipe). Welds are made utilizing the consumable insert - tungsten inert gas first pass technique.

The pipe alley and auxiliary feedwater pump turbine room are provided with watertight steel doors to contain the energy released by a postulated break. The compartments are connected by two blowout panels to allow venting through a common discharge path.

Postulated break locations shown on Figure 3.6-24 have been sleeved and restrained to limit pipe break mass flow rates and preclude pipe whip damage to vital equipment. Typical sleeve and restraint designs for this line are shown on Figure 3.6-25.

3.6.5.14 Electrical Cable Environmental Qualification

All electrical cable types which are used for safety-related equipment in areas subject to adverse environmental conditions from pipe ruptures have been qualified for continued operation in these environments.

Qualification tests consisted of exposure of the cable samples to thermal aging (e.g. 250°F for 7 days) radiation exposure (e.g. 100 x 10^6 R equivalent air dose with a Co^{60} source), and cyclic steam and chemical spray (e.g. 340°F, 105 psig steam, Boric Acid and Sodium Hydroxide, cycled for 14 days). Testing after exposure showed no significant detrimental change in insulation resistance, insulation dielectric breakdown capability, or cable strength and ductility parameters.

3.6.6 References for Section 3.6

1. Letter, A. Giambusso (AEC) to F. W. Schneider (PSE&G), dated December 18, 1972, with attachment "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment," Letter, D. B. Vassallo (AEC) to F. W. Schneider (PSE&G), dated January 31, 1973, with attachment "Errata Sheet for 'General Information Required for Consideration of the Effects of a Piping System Break Outside Containment.'"

2. Griffith, A. A., "The Phenomena of Rupture and Flow Solids," Philosophic Transactions of the Royal Society of London, Vol. 221, pp. 163-198, 1920.

3. Letter, R. C. De Young (AEC) to F. W. Schneider (PSE&G), dated May 21, 1973.

4. Branch Technical Position MEB 3-1, "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment," attached to SRP Section 3.6.2, Rev. 2, June 1987.

5. Branch Technical Position SPLB 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment," attached to SRP Section 3.6.1, Rev. 2, October 1990.

6. Letter from Mr. James C. Stone, NRC, to Mr. Steven E. Miltenberger, PSE&G, dated May 25, 1994, "Leak-Before-Break Evaluation of Primary Loop Piping, Salem Nuclear Generating Station, Units 1 and 2".

3.7 SEISMIC DESIGN

Plant structures and components are designed according to the criteria described herein to resist the dynamic forces resulting from the earthquake conditions postulated for the site. These structures and components are analyzed either dynamically or statically for the respective equivalent loadings according to their classification.

Two types of seismic loadings are considered: Operational Basis Earthquake (OBE) and Design Basis Earthquake (DBE).

For the OBE loading condition, the nuclear steam supply system is designed to be capable of continued safe operation. Therefore, for this loading condition critical structures and equipment needed for this purpose are required to operate within design limits. The seismic design for the DBE is intended to provide a margin in design that assures capability to shut down and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that required critical structures and components do not lose their capability to perform their safety function. This has come to be referred to as the "no-loss-of-function" criteria and the loading condition as the "design basis earthquake" loading condition.

Not all critical components have the same functional requirements for safety. For example, the reactor containment must retain capability to restrict leakage to an acceptable level. Therefore, based on present practice, general elastic behavior of this structure under the "Design Basis Earthquake" loading condition must be ensured. On the other hand, many components can experience significant permanent deformation without loss of function. Piping and vessels are examples of the latter where the principal requirement is that they retain their contents and allow fluid flow.

What follows in Section 3.7 is a description of the original design basis seismic analyses performed for Salem Units 1 and 2. The replacement of the Unit 1 steam generators necessitated reanalysis of the Unit 1 RCS. This reanalysis is described in Appendix 3B.

3.7.1 Seismic Input

3.7.1.1 Design Response Spectra

The El Centro ground motion of May 18, 1940, was recommended by Dames and Moore as the most appropriate motion for the site. Its peak horizontal acceleration was normalized to 0.10g and 0.20g for Operating and Design Basis Earthquake, respectively. Two-thirds of the above mentioned values are used for vertical ground motions, and they are considered to be acting simultaneously with the horizontal ground motion.

Modified Housner's average response spectra as shown on Figures 3.7-1 and 3.7-2 are used for manual modal analysis.

The Salem ground response spectra are generally lower than those normalized from Regulatory Guide 1.60. However, the conservative damping values used in the Salem analyses compensate for the differences. Furthermore, time history input was used for Category I structure seismic analyses. The normalized El Centro 1940 ground response N-S components, as shown on Figures 3.7-1 and 3.7-2, are considerably higher than the Salem ground response spectra.

3.7.1.2 Design Response Spectra Derivation

The tabulation which follows provides a comparison of the damping values used in the seismic analysis with those identified in Regulatory Guide (RG) 1.61. It can be seen that the damping values used in the Salem analysis are consistently more conservative than the Regulatory Guide recommended values.

first 10 feet of weld made by each welder was 100 percent radiographed.

The following preliminary tests were made during the liner erection using the test channels:

1. All welds were covered by channels and zoned after which a strength test was performed by applying 54 psig air pressure to the channels in a zone for a period of 15 minutes. The exposed welded joints were given a soap test for leaks. If bubbles indicated a leak, the leak was repaired and the zone retested.

2. The zones of channels were then retested to a pressure of 47 psig with a 20-percent, by weight, freon-air mixture. The entire run of the channel to plate weld was traversed with a halogen leak detector. If a leak was detected, repairs were made and a retest performed.

3. In addition, the zone of channels was held at the 47 psig air pressure for a period of 2 hours. When pressure drop exceeded the standards, zones were repaired and retested.

Erection Tolerances

1. Overall out of roundness
   - below El. 130 feet: ± 2 inches
   - above El. 130 feet: ± 4 inches

2. Overall deviations out of plumbness - 1/500 of the height.

Equipment Hatches, Personnel Locks, and Penetration Sleeves

The detail specification required that the equipment hatches, except as noted for the outage equipment hatch, and personnel locks be made from ASTM A-516, Grade 60, conforming to ASTM A-300 requirements. In addition, the steel was normalized by heating to 1,700°F (± 50°) and cooling in still air and "V" notch tested to a minimum of 15 foot - pounds at -40°F in accordance with ASTM Specification A-370-65. For the material on the interior bulkhead which is not subjected to low temperatures, the material was required to pass a Charpy "V" Notch test of 15 foot - pounds at +20°F, in accordance with ASTM Specification A-370-65. The OEH conforms to ASME Code, Section VIII material requirements.

Access hatches, except as noted, were fabricated and tested at the fabrication shop. The personnel locks and any portion of the equipment access door extending beyond the concrete shell conforms to the requirements of the 1968 edition of the ASME, Section III for Class B Vessels. The chambers were completely fabricated in the shop and the weldments were inspected by the Hartford Insurance Group. The chambers were not stamped as a Class B pressure vessel, but were covered by an equivalent to a Manufacturer Partial Data Form N-1A for the personnel locks and covered by a Manufacturer Partial Data Form for the equipment hatches. The user and his authorized representative monitored shop test procedures at the fabrication shop and audited all records. The OEH conforms to the requirements of ASME code, Section VIII.

The piping penetration sleeves are carbon steel and are described in Section 3.8.1.6.8.10. The electrical penetration sleeves are of Schedule 80 carbon steel. The piping and electrical penetration sleeves were welded to the liner plate assemblies at the fabrication shop in accordance with ASME, Section III, Class B vessels, except for stamping. The weldments were inspected in the shop by The Hartford Insurance Group and are covered by a Manufacturer Partial Data Form.

Strength and leak tests were performed in the shop on all access hatches. Leak test of the penetration sleeve welded channel was also performed in the shop.

steel dome liner were lifted into place, braced with wind girders, and welded into their final locations.

3.8.1.6.8.8 Penetrations

In general, a penetration consists of a sleeve embedded in the concrete wall and welded to the containment liner. The weld to the liner is shrouded by a continuous channel which is test pressurized to demonstrate the integrity of the penetration-to-liner weld joint. The pipe, electrical conductor, duct, or equipment access hatch passes through the embedded sleeve and the end of the resulting annulus is closed off, either by welded end plates, bolted flanges, or a combination of these. Provision has been made for differential expansion and misalignment between each pipe and sleeve. No piping loads are imposed on the liner. Pressurizing connections are provided to demonstrate the integrity of the penetration assemblies.

There are three large openings that significantly perturb the reinforcing pattern. One is the equipment hatch with an 18-foot diameter outer barrel; the others are two personnel hatches with 9 foot-9 inch diameter outer barrels. As a rule of thumb, only openings having diameters greater than 2 1/2 times the wall thickness are considered to require detailed analysis. The design and analysis for these three large openings are described in Section 3.8.1.6.8.9. The main wall reinforcing, consisting of vertical and horizontal reinforcing bars, is bent around all the openings. Continuity of shell reinforcement is therefore maintained. For large openings, in addition to these bars, circular reinforcing bars have been provided to take care of axial thrust and principal moments around the opening. Radial stirrups have been provided to take care of the torsion and shear. This combination of reinforcing bars takes care of all primary and secondary stresses.

3.8.1.6.8.9 Equipment and Personnel Access Hatches

Equipment and personnel access hatches, except as noted for the outage equipment hatch, OEH, are fabricated from A516, Grade 60 steel normalized to A300 requirements. All personnel locks and the portion of the equipment access hatch extending inside the containment structure beyond the concrete shell are designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B. The Code was used as a guide; therefore the N Stamp requirement is waived. The equipment and personnel hatch details are as shown on Figures 3.8-35 and 3.8-36, respectively. The OEH is designed in accordance with ASME VIII.

The hatch barrel is embedded in the containment wall and welded to the liner. Provision is made to test pressurize the space between the double gaskets of the door flanges and the weld seam channels at the liner joint, hatch flanges, and dished door. The personnel hatches will be double door, mechanically latched, welded steel assemblies. A quick-acting type equalizing valve connects the personnel hatch with the interior of the containment vessel for the purpose of equalizing pressure in the two systems when entering or leaving the containment. The personnel hatch doors are interlocked to prevent both being opened simultaneously and to ensure that one door is completely closed before the opposite door can be opened. Remote indicating lights and annunciators situated in the control room indicate the door operational status. Provision is made to permit bypassing the door interlocking system to allow doors to be left open during plant cold shutdown. Each door lock hinge is designed to be capable of independent three-dimensional adjustment to assist proper seating. An Emergency Lighting and Communication System powered from an external emergency power supply is provided in the lock interior. Emergency access to either the inner door, from the containment interior; or to the outer door, from outside, is possible by the use of special door unlatching tools.

Plan and elevation drawings of the personnel air lock with all electrical and piping penetrations identified are provided on Figures 3.8-36, 3.8-37, and 3.8-38.

accidental eccentricity. For information concerning the extent to which the internal structure and its walls are capable of withstanding the stresses resulting from the accidental eccentricity, see Section 3.7.

The following structures are removable; provisions have been made to prevent them from becoming missiles.

Hatch covers at Elevation 130 feet

They are 4-foot thick massive concrete blocks bolted down to the slab to withstand any uplift pressure.

Missile shield over Reactor Vessel

It is a concrete slab 17 feet x 17 feet x 1 foot with a 1-inch steel plate at bottom face to stop missiles coming from the reactor vessel head. It is secured to prevent it from becoming a missile.

Lead blocks at Elevation 100 feet in fuel transfer canal area and at Elevation 89 feet-6 inches to 95 feet-10 inches transfer chamber

They are for radiation protection for the gap between containment exterior wall and interior structure. Blocks are held in place by angle frames and steel plates to hold them during earthquake motion.

Hatch cover over fuel transfer chamber at Elevation 100 feet

It is a steel enclosure filled with poured lead. It is laterally

restrained, subject to no jet force and could never become a missile.

3.8.4 Other Category I Structures

3.8.4.1 Summary Description

The Category I structures other than the containment structures are listed in Section 3.2. They are Auxiliary Building, Fuel Handling Buildings, Service Water Intake Structure, Class I water tank foundations, and the Class I equipment supports.

The orientation of the principal structures is shown on Figure 3.8-56. The general arrangements of Containment Buildings, Auxiliary Building, and Fuel Handling Buildings are shown in Section 5.

What follows in Section 3.8.4 is a description of the original design basis analyses performed for the "other" Category 1 structures, described above, in Units 1 and 2. The replacement of the Unit 1 steam generators necessitated reanalysis of the Unit 1 RCS and its component supports. This reanalysis is described in Appendix 3B.

3.8.4.2 Design Codes

Category I structures were designed under the following codes:

1. Building Code Requirements for Reinforced Concrete, ACI 318-63.

2. AISC Manual of Steel Construction, 6th Edition or later edition, as applicable.

3.8.4.3 Loads and Loading Combinations

Loads and load combinations for Category I structures under SSE or tornado conditions are similar to those of the containment except for LOCA pressure and temperature loadings. The working stress design method was used for operating and OBE conditions. (No load factor was used for OBE loadings.) For combination of containment loadings and load symbols, see Section 3.8.1.3.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

Method of Analysis

The original design basis analysis of the Unit 1 and 2 Reactor Coolant Loop/Supports System was conducted based on an integrated analytical model which included the effects of the supports and the supported equipment. What follows in Section 3.9 is a description of these original design basis analyses. The replacement of the Unit 1 steam generators necessitated reanalysis of the Unit 1 RCS and its component supports. This reanalysis is described in Appendix 3B.

A three-dimensional, multi-mass, elastic-dynamic model was constructed to represent the Reactor Coolant Loop/Supports System (The model is as shown on Figure 3.6-2). The seismic floor spectrum at the internal concrete to support interface, obtained from an elastic-dynamic model of the reactor containment internal structure, was used as input to the piping analysis.

The dynamic analysis employed displacement method, lumped parameter, stiffness matrix formulations, and assumptions that all components behave in a linearly elastic manner. The proprietary computer code WESTDYN was used in this analysis.

Normal Operating Loads

System design operating parameters were used as the basis for the analysis of equipment, coolant piping, and equipment support structures for normal operating loads. The analysis was performed using a static model to predict deformation and stresses in the system under normal operating conditions. The analysis with respect to the piping and vessels was in accordance with the provisions of USAS B31.1 and ASME Section III. Results of the analysis gave six generalized force components, three bending moments, and three forces. These moments and forces were resolved into stresses in the pipe in accordance with the applicable codes. Stresses in the structural supports were determined by the material and section proprietaries assuming linearly elastic small deformation theory.

Seismic Loads

Analysis for seismic loads was based on a dynamic model analysis. The appropriate floor spectral accelerations were used as input forcing functions to the detailed dynamic model. The loads developed from the dynamic model were incorporated into a detailed support model to determine the support member stresses.

Blowdown Loads

Analysis of blowdown loads resulting from a loss-of-coolant accident (LOCA) was based on the time-history response of simultaneously applied blowdown forcing functions on a single broken loop dynamic model. The forcing functions are defined at points in the system loop where changes in cross section or direction of flow occur such that differential loads are generated during the blowdown transient. The loads developed from the dynamic model were incorporated into a detailed support model to determine the equipment support member stresses.

Combined Blowdown and Seismic Load

The stresses in components resulting from normal loads and the worst case blowdown analysis were combined with the worst case seismic analysis to determine the maximum stress for the combined loading case. This is considered a very conservative method since it is highly improbable that both maxima will occur at the same instant. These stresses were combined to determine that the Reactor Coolant Loop/Supports System will not lose its intended functions under this highly improbable situation to assure the station capability for safe shutdown. The limiting stress criteria to be used in the analysis are defined in Section 5.2.

3.12 CONFORMANCE TO RULES ISSUED AFTER PLANT LICENSING

3.12.1 NRC Rule On Station Blackout

On July 21, 1988, the Code of Federal Regulations, Title 10, Part 50 was amended to include a new Section 50.63, "Loss of All Alternating Current Power, " (Station Blackout). The Station Blackout (SBO) rule requires that each light-water cooled nuclear power plant licensed to operate must be able to withstand and recover from an SBO. An SBO is defined in 10CFR50.2 as the complete loss of alternating current (AC) electric power to the essential and non-essential switchgear busses (i.e., loss of offsite power concurrent with a turbine trip and unavailability of the onsite emergency ac power system). SBO does not include loss of station batteries or loss of AC power from station batteries through inverters, nor does it assume a concurrent single failure or design basis accident of the affected Unit.

The NRC issued Regulator Guide (RG) 1.155 in August of 1988, to provide the industry with guidance that was acceptable for meeting the requirement of 10CFR50.63. In RG 1.155, the NRC states that NUMARC 87-00 (Reference 1) also provides guidance acceptable for meeting the requirements of 10CFR50.63, except when RG 1.155 takes precedence over NUMARC 87-00 as indicated in Table 1 of RG 1.155.

3.12.1.1 Conformance to NRC Rule on Station Blackout

An SBO coping analysis was performed to determine SGS's coping duration and ability to cope with an SBO. This coping duration was based on:

a. Offsite Power Design Characteristic
b. Emergency AC Power Supply System Configuration
c. Calculated EDG Reliability; and
d. Allowed EDG Target Reliability

The coping duration for SGS was calculated as four hours in accordance with NUMARC 87-00, Section 3.0 with the exception of the frequency of Loss of Offsite Power events due to severe weather (SW) and Extremely Severe Weather (ESW). Site-specific weather data was used to determine the SW and ESW frequency as detailed in Report No. NUS-5175, Rev. 1 (Reference 2).

The ability to cope with an SBO event is based on the ability to maintain "appropriate containment integrity" (as defined in RG 1.155), provide adequate condensate inventory for decay heat removal, provide adequate class 1E battery capacity and compressed air capacity for the coping duration period, and evaluate equipment operability due to loss of ventilation. The ability to cope with an SBO event is described in programmatic standard SC.DE-PS.ZZ-0040 (Q), "Salem Station Blackout Program."

3.12.2 References

1. NUMARC 87-00, "Guidelines and Technical Bases for Initiatives Addressing Station Blackout at Light Water Reactors," Rev. 1, August 1991.

2. Halliburton NUS Environmental Corporation, NUS-5175, Rev. 1, "Estimated Frequency of Loss of Off-Site Power due to Extremely Severe Weather (ESW) and Severe Weather (SW) for Salem and Hope Creek Generating Stations, " March 1992.

which were prior to the inception of the NRC's quality group classification system. The Regulatory Guide was not issued until March 1972, at which time construction was well underway. The codes and standards which were used are presented in the appropriate sections of the FSAR.

Regulatory Guide 1.27 - ULTIMATE HEAT SINK (Revision 2)

The Salem Station design generally conforms with the intent of the Regulatory Guide (FSAR Section 9.2).

Regulatory Guide 1.28 - QUALITY ASSURANCE PROGRAM REQUIREMENTS (DESIGN AND CONSTRUCTION)

The quality assurance program for the design and construction of the Salem Station uses Appendix B to 10CFR50 as a guideline (see Section 17) thereby conforming with the intent of the Regulatory Guide.

Regulatory Guide 1.29 - SEISMIC DESIGN CLASSIFICATION, 8/73

The Salem Station design conforms with the intent of the Regulatory Guide. Previously, the only area of non-conformance with the Regulatory Guide was in the classification of the Spent Fuel Pool Cooling (SFPC) System. SFPC piping and pipe supports are analyzed as seismic class I. SFPC components have been seismicly evaluated under SQUG GIP methodology. The basis for this classification is provided in Section 9.1.

Regulatory Guide 1.30 - QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING INSTRUMENTATION AND ELECTRIC EQUIPMENT, 8/72 (endorses N45.2.4)

The Salem Station design conforms with the intent of the Regulatory Guide.

Regulatory Guide 1.31 - CONTROL OF FERRITE CONTENT IN STAINLESS STEEL WELD METAL

The Regulatory Guide states that weld deposits should contain between 5 and 12 to 15 percent delta ferrite. It is not practical to specify "absolute minimum" or even maximum delta ferrite limits as a basis for acceptance or rejection of otherwise acceptable austenitic stainless steel welds.

Westinghouse places control on the actual wire analysis for inert gas welding processes and on the final weld deposit for the fluxing weld process.

In the case of the bare wire, when used with inert gas processes, although the wire may contain 5 percent ferrite, only about 1 or 2 percent ferrite will be developed in the resultant weld deposits. This is not the case in fluxing processes such as when using coated arc electrodes or submerged arc, since the flux is enriched with additional ferrite formers resulting in higher ferrite contents in the resultant weld deposits. Similarly, the amount of ferrite that may exist in any given weld will vary across the width of the weld deposit depending upon the base materials being joined. For example, when fully austenitic wrought product is welded, the interface regions will be practically 0 percent ferrite because of the resultant base metal dilution, but it will progressively increase toward the weld centerline. Conversely, when a two-phase (austenitic + ferrite) cast product which normally contains over 15 percent ferrite is welded, the interface region will be high in delta ferrite content depending upon the amount of delta ferrite available and diluted from the casting base material.

The ferrite distribution in a weld will also vary depending upon the weld position. That is: in areas of the downhand and horizontal position, weld deposit ferrite will be the highest; whereas, in the vertical and overhead position, weld deposit

The Vice President, Operations has ultimate responsibility at the station level for the establishment and execution of the station Radiological Protection Program. He implements the Program to meet the requirements of 10CFR20, Regulatory Guides, and the Technical Specifications.

The Radiation Protection Manager (RPM) is responsible for implementation of the Nuclear Business Unit Radiation Protection Program at the Salem and Hope Creek generating stations. The RPM reports administratively to the General Manager-Salem Operations, but has direct access to the Vice President - Operations, in matters of radiation protection and ALARA. The RPM maintains liaison with other NBU departments and upper management regarding the program, and directs the Radiation Protection Program through the Radiation Protection Superintendents. The RPM is the member of the NBU management who is responsible for the ALARA program, and reviews the program to determine how personnel dose may be reduced.

The Radiation Protection Superintendents are responsible to the RPM for the day-to-day functions in the ALARA, Operations and Support areas.

The RPM (or his designate):

1. Ensures ALARA pre-job planning of major work items that are estimated to give large man-rem exposures

2. Establishes an effective Radiation Work Permit Program to control individual exposures

3. Ensures that adequate controls are in place to prevent the uncontrolled release of radioactive materials

4. Performs periodic formal assessments of the content and implementation of the NBU ALARA program including recommendations for improvements.

5. Ensures that ALARA requirements and concepts are appropriately included in the NBU ALARA program.

Design and equipment changes are reviewed by the Station Operations Review Committee (SORC).

A Radiation Protection Program has been established and implemented for both Salem and Hope Creek. Procedures are written and approved covering such subjects as access control, radioactive material control, dosimetry, surveys, and radiation exposure permits. Through the use of these established procedures, and with guidance and supervision by the Radiation Protection Superintendents and Supervisors, work will be performed in accordance with ALARA philosophy.

The typical portable radiation survey instruments are described in Section 12. The criteria for selection of the portable instruments includes:

1. Ability of instrument to perform in its intended use with reliability and accuracy

2. Ease of calibration and repair

3. Interchangeability of components

APPENDIX 3B

STRUCTURAL EVALUATION OF THE UNIT 1 RCS WITH MODEL F STEAM GENERATORS

The Series 51 steam generators in the Unit 1 Reactor Coolant System (RCS) were replaced with Model F generators taken from the unfinished Seabrook Nuclear Station Unit 2 RCS. The replacement of the steam generators required reanalysis of the Unit 1 RCS to demonstrate that the original structural design basis criteria would still be met. What follows in this appendix is a description of the analytical models developed, and analyses performed, for this structural reanalysis of the Unit 1 RCS. The information given in the body of the SAR (outside this appendix) describes the original design basis modeling and analyses performed for the Salem RCS (both units). Therefore, the complete structural design basis of the Unit 1 RCS consists of that information in the body of the SAR plus the modifications to that information as described in this appendix.

3B.1 Scope of Evaluation

FTI performed a structural analysis of the Unit 1 Reactor Coolant System (RCS) with the Model F steam generators in place. A plan view of the RCS is shown in Figure 3B-1. The intent of this analysis was to demonstrate that the RCS piping, components and supports, with the Model F steam generators in place, remain in compliance with the requirements set forth in Westinghouse and PSE&G documents describing the original Salem Unit 1 design basis. The demonstration of compliance with original design basis requirements was primarily accomplished through load and stress comparisons to original design basis loads and original design basis (or allowable) stresses.

3B.2 Analysis Overview

Thermal-hydraulics models of all four loops of the RCS primary side, the secondary side of the Model F steam generator (SG) and the containment building were developed. These models consist of networks of fluid control volumes and flow paths which were used to determine hydraulic forcing

functions (pressure time histories) resulting from a postulated break. The pressure time histories generated were converted to force time histories which were then applied to the structural model in the HELBA loading analyses.

The thermal-hydraulics models were analyzed for seven postulated breaks:

- Surge line break at Hot Leg (HL) nozzle
- 14" Residual Heat Removal (RHR) line break at the HL nozzle
- 6" RHR line break at the HL nozzle
- Safety Injection (SI) line break at the Cold Leg (CL) nozzle
- Main Steam (MS) line break at the SG nozzle
- Feedwater (FW) line break at the SG nozzle
- Surge line break beyond the first surge line elbow from the HL

Time histories representing thrust, Jet Impingement (JI), Asymmetric Cavity Pressure (ACP) and forces at changes in flow area or direction were generated for each of these seven breaks for application to the structural model. The breaks envelope the effects of breaks in the smaller attached piping. Note that breaks in the primary piping were not considered because Leak-Before-Break (LBB) has been approved for the Salem units (see Reference 1). Also, Arbitrary Intermediate Breaks (AIBs) in the piping attached to the reactor coolant loop piping have been eliminated from consideration at the Salem units.

Concurrent with the development of the thermal-hydraulic models, a full four loop structural model of the Salem Unit 1 RCS was developed. This model included centerline representations of the Reactor Vessel (RV), Model F SGs, Reactor Coolant Pumps (RCPs), RCP motor stands/motors and primary piping. Detailed models of the SG Lower Supports (SGLSs) and RCP supports were also included. Stiffnesses were determined for the RV supports and SG Upper Supports (SGUSs) which were then incorporated into the model as spring elements. All attached piping, including the spray and surge lines, was decoupled from the model per the criteria given in Welding Research Council (WRC) Bulletin 300 (Reference 2).

After the structural model was completed and reviewed, the 100% power thermal expansion load case was analyzed. To provide a secondary check of the model's accuracy, the displacements resulting from this analysis were compared to those from the original design basis analysis of the RCS as performed by Westinghouse. The differences in these two sets of displacements were shown to be minor or were shown to occur due to the differences in modeling and analysis techniques employed by Westinghouse and FTI.

The structural model was then analyzed for the following applied loads:

- Longitudinal pressure (stress)
- Pressure expansion
- Normal operating deadweight
- Hydrostatic deadweight
- 100% power thermal
- 100% power thermal with the elastic moduli for the RCS piping taken at 70 degrees Fahrenheit.
- Seismic - Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE)
- High Energy Line Break Accident (HELBA) - seven break cases were analyzed, as noted above.

Using the results from the loading analyses of the structural model, several approaches were taken to demonstrate that the Salem Unit 1 RCS, with model F SGs, remains in compliance with the original design basis requirement:

- The component nozzle and support lug loads and the RV support loads resulting from the FTI loading analyses were compared to those from Westinghouse equipment specifications or stress reports.

- The loads/stresses in the SGLS, SGUS and RCP support were compared to those generated in the original analysis of the RCS or to appropriate allowable stresses.

In addition to the structural analyses1 the effects of the Model F SGs on surge line stratification and on the thermal stress in piping attached to the RCS were assessed:

- The effect of the Model F SGs on surge line stratification (see NRC Bulletin 88-11(Reference 16) were evaluated and the surge line stresses and fatigue were found to meet the requirements of Section NB-3600 of the 1986 Edition of Section III to the ASME Boiler and Pressure Vessel Code (Reference 3). The additional fatigue usage caused by introduction of the Model F SGs into the RCS was conservatively calculated and added to the maximum usage calculated by Westinghouse and this total usage was shown to remain below 1.0.

- The effect of the Model F SGs on Salem's existing NRC Bulletin 88-08 (Reference 17) analyses were evaluated and it was concluded that the existing analyses remain valid. The potentials (temperature, pressure and flow rate) which drive valve leakage and the effects of postulated valve leakage were evaluated and it was concluded that these things are not significantly affected by introduction of the Model F SGs into the RCS and therefore that the existing analyses remain valid.

3B.3 Thermal-Hydraulics Models and Analyses

Thermal-hydraulic analyses were performed for the pipe break load cases identified above. All of these analyses were performed using initial conditions corresponding to 100% power for the RCS primary side, SG secondary side and containment building environment.

3B.3.1 RCS Hydraulic Model and Analyses

A thermal-hydraulic model consisting of a network of fluid control volumes and flow paths was developed for the primary side of the RCS (all four loops) using the FTI hydraulic code, CRAFT2 (see Section 3B.9). The model, after being initialized to normal steady state pressures and temperatures, was used to determine hydraulic forcing functions (force time histories) at changes in area and flow direction which would occur during rapid depressurization after a postulated HELBA. The force time histories were then oriented to the global coordinate system for input to the structural model using the FTI computer code, BWHIST (see Section 3B.9).

The break opening times used for the primary side breaks were calculated as follows:

- The distance from the center of the first elbow past the break to the location where a plastic hinge forms due to thrust from the break (the plastic length) is calculated;

- The mass of 2/3 of the pipe and its contents between the break and the plastic hinge is calculated;

- The acceleration necessary to move this mass, given the thrust force, is calculated; and

- The parabolic equation relating distance, time and acceleration is used to generate a break opening time table. The distance used is the axial separation necessary to achieve a full double ended break.

This method leads to conservatively fast break opening times because: the effect of supports/restraints between the break and the postulated plastic hinge are ignored, and, separation required for full break opening is assumed to occur in the axial direction which is a shorter distance than that required in the direction transverse to the pipe.

Another important factor in blowdown analysis is the discharge correlation used. The discharge correlation determines the mass flux through the break opening given the pressure and enthalpy in the RCS near the break. For these analyses, the Modified Zaloudek-Moody combined correlation was used. In this combination, the Modified Zaloudek correlation gives the break mass flux when the water near the break is subcooled (i.e. above saturation pressure). The Moody correlation gives the break mass flux when the water near the break is saturated (i.e. at saturation pressure) or superheated (i.e. below saturation pressure).

Mass and energy release data for the breaks analyzed was saved for later use in the ACP loading of the RCS components (see Section 3B.3.3). Other data resulting from the hydraulics analysis of the primary breaks (temperatures, pressures, flow rates, steam quality, etc) was used to evaluate potential JI loading of the RCS components (see Section 3B.3.4).

3B.3.2 Model F SG Hydraulic Model and Analyses

A thermal-hydraulic model consisting of a network of fluid control volumes and flow paths was developed for the Model F SG using the FTI hydraulic analysis code, CRAFT2. The model, after being initialized to normal steady state pressures and temperatures, was used to determine hydraulic forcing functions (pressure time histories) at changes in area and flow direction in the Model F SG, which occur during rapid depressurization after a postulated secondary side HELBA. The pressure time histories were converted to force time histories, by multiplying them by the appropriate area, and were oriented to the global coordinate system for input to the structural model using the FTI computer code, BWHIST.

The Model F SG blowdown model accounts for the flow limiter in the SG MS outlet nozzle. The flow limiter is designed to prevent a rapid SG depressurization by choking the steam flow should a steam line break occur and will minimize the pressure drop loading on the SG internals.

Break opening area versus time was calculated in the same manner as it was for the RCS blowdown cases and the break discharge correlation used was the same as that used for the RCS blowdown cases (see Section 3B.3.1).

Mass and energy release data for the breaks analyzed was saved for later use in the ACP loading analysis of the RCS (see Section 3B.3.3). Other data resulting from the hydraulics analysis of the primary breaks (temperatures, pressures, flow rates, steam quality, etc.) was used to evaluate potential JI loading of the RCS components (see Section 3B.3.4).

3B.3.3 Asymmetric Cavity Pressurization (ACP) Analysis

A thermal-hydraulic model consisting of a network of fluid control volumes and flow paths was developed to represent the containment building cavities surrounding the SGs and RCPs. This model, with mass and energy release data from the RCS and Model F SG hydraulic analyses (Sections 3B.3.1 and 3B.3.2), was used to determine pressure time histories in the control volumes using the FTI hydraulic analysis code, COMPAR2 (see Section 3B.9). The pressure time histories were converted to force time histories, by multiplying them by the appropriate surface areas of the components, and were oriented to the global coordinate system for input to the structural model using the FTI computer code, BWHIST.

The ACP analysis model was constructed using the guideline of NUREG 0609 (Reference 4) and SRP Section 6.2.1.2 of NUREG 0800 (Reference 5). As suggested in NUREG 0609, the Homogeneous Equilibrium Model was used for the critical flow correlation for flow between control volumes.

3B.3.4 Jet Impingement Analysis

Temperatures, pressures, flow rates, steam quality and other data from the RCS and Model F SG hydraulic analyses (Sections 3B.3.1 and 3B.3.2) was used to determine JI forces acting on the RCPs and SGs as well as reaction (thrust) forces acting at the break. JI forces were calculated using the methodology outlined in ANSI Standard ANS-58.2 (Reference 6).

3B.4 Structural Model

The structural model, consisting of centerline representations of the RV, Model F SG, RCP, RCP motor/motor stand and the RCS piping, was developed using FTI's piping/structural analysis computer code, BWSPAN (see Section

3B.9). The RV and SGUS were represented as spring rates and and the SGLS and RCP supports were explicitly modeled. Elastic moduli for the model elements were calculated based on the 100% power (normal operating) temperatures, except as noted in Section 3B.5.6. Figures 3B-2 through 3B-12 at the end of this section show the BWSPAN model of the RCS.

3B.4.1 RCS Piping and Component Models

Shell sections of the RV, Model F SGs and RCPs were modeled as pipe elements having the same cross section properties as the shells. The heads of the components, being much stiffer in bending than the shells, were modeled with idealized cross sections that are much stiffer than those representing the component's shell. "Spider" elements connecting the centerline component model elements with the nozzles or support points were also represented as stiff elements. Local flexibility at the shell/nozzle or support interface was modeled where applicable. The RCS piping and elbows were modeled as pipe using nominal dimensions.

3B.4.2 Component Support Models

The structural steel members making up the RCP and SG lower supports were explicitly modeled. The SG support model reflects the modifications to the SG columns which were required for interface with the Model F SG (the Model F SG has a support ring integral to the tubesheet while the Series 51 SG has lugs welded to its channel head). Cross sectional properties for the various members were taken from the original design basis analysis of the RCS except for the modified SG column properties which were hand calculated. An isolated model of the RV support steel and concrete was used to generate the RV support stiffnesses, which were input into the full RCS model as springs. The horizontal stiffnesses of the SGUS were hand calculated and input into the full RCS model as springs also.

The RCP and SG lower supports are connected to the RV cavity wall through gapped members near their tops. These gapped, one-way restraints allow free expansion up to 100% power while still providing stability of the supports during the large bore pipe breaks postulated in the original design of the Salem units. The large bore breaks have been eliminated by LBB as noted above. Note that these restraints are designed to maintain a small gap even at the 100% power condition. In the analysis of the Salem RCS performed by

Conrad and Associates, it was determined that relative seismic motions between the RCP and the SG lower support at the one-way restraints were in the range of 0.01" which was not enough to close the hot gap of these restraints. Therefore, these restraints were considered inactive for seismic load cases in the Conrad analysis. This is a reasonable and conservative approach that was also taken in the FTI analysis.

3B.4.3 Model Mass

The mass of the piping, components, component supports, component internals. component and piping insulation, and water and steam entrained in the components and piping was included in the structural model. The weight of the Control Rod Drive Mechanisms (CRDMs) and of the RCP motor stand and motor were also included in the model. The mass of the CRDMs and RV closure head lifting rig, the SG heads, the whip restraint steel strapped to the XOL elbows, the splitter in the XOL elbow and the SGUS were all represented in the model as lumped mass. The remainder of the weight was distributed (consistent mass). The lumped and distributed masses were applied such that the Centers of Gravity (CGs) were accurately located in the model.

3B.5 Structural Loading Analyses

The structural model was analyzed for the following applied loads:

- Longitudinal pressure (stress)
- Pressure expansion
- Normal operating deadweight
- Hydrotest deadweight
- 100% power thermal
- 100% power thermal with the elastic moduli for the RCS piping taken at 70 degrees Fahrenheit
- Seismic - Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE)
- High Energy Line Break Accident (HELBA) - Seven break cases were analyzed.

All of the above load cases were analyzed using 100% power (normal operating) temperatures and pressures, except as noted in Section 3B.5.6. Methods used in the loading analyses are in agreement with those used in the original design basis analysis or are more conservative.

3B.5.1 Longitudinal Pressure Stress

The design pressure for the Salem reactor coolant loop was applied to those model sections having piping cross sections, i.e., to the RCS piping and components. These pressures were used to calculate longitudinal pressure stress for use in the pipe stress calculations.

3B.5.2 Pressure Expansion

In keeping with the original design basis analysis of the Salem RCS as performed by Westinghouse, a pressure expansion load case was analyzed. Pressure expansion loading is similar to thermal expansion loading in that it is displacement limited, that is, it results in secondary stress in the piping and components and primary stress in the supports. This case is treated as a thermal analysis with the coefficients of thermal expansion derived from the equations for pressure expansion of thick wall vessels.

The component horizontal restraints are shimmed such that there is the potential for small gaps when the system reaches 100% power. Because of these gaps at hot condition, the radial restraints at the RCP support lugs, at the SG lower support lugs and at the SG upper support bumpers are not considered active for the static load cases. The SG upper support snubbers are also not active for static load cases. The RV supports are not designed to resist loads radial to the RV centerline and so are not active in that direction.

The tangential restraints at the RV support pads and at the RCP and SG support lugs are considered active for the static load cases because they are two-way restraints (there is a bumper on either side of the pad/lug in the tangential direction). Because the tangential restraints are two-way, one or the other side will be in contact and the tangential restraints were therefore made active.

3B.5.3 Normal Operating Deadweight

Deadweight loading consists of three parts:

1. Material and Water Densities. These distributed weights represent piping, support steel as well as the water entrained in the piping.

2. Distributed (Linear) Weights. These weights represent component shells and heads, internals, entrained water and insulation and in the case of the RCP they represent the motor and motor stand weight.

3. Applied Forces. These forces represent component head weights and attachment weights (supports and whip restraints, CRDMs, etc).

The support/restraint scheme used for this load case is the same as that used for the pressure expansion load case (see Section 3B.5.2).

3B.5.4 Hydrotest Deadweight

The RCS was analyzed for loads resulting from hydrotest. The input required for this analysis is the same as that for the normal deadweight load case as described in Section 3B.5.3 except that the difference in water weight between the normal operating and flooded SG is accounted for.

The support/restraint scheme used for this load case is the same as that used for the pressure expansion load case (see Section 3B.5.2).

3B.5.5 100% Power Thermal

This thermal load case uses the moduli of elasticity at the 100% power (hot) temperature for all model sections. Linear coefficients of thermal expansion, in terms of inches per foot, are input for all model elements, including the supports.

The support/restraint scheme used for this load case is the same as that used for the pressure expansion load case (see Section 3B.5.2).

3B.5.6 100% Power Thermal with Ecold for RCS Piping

This thermal load case uses the moduli of elasticity at 70° F for the RCS piping elements and the moduli of elasticity at the 100% power (hot) temperature for the remainder of the model elements. This analysis was run because the pipe stress code of record, the 1955 ASA B31.1 Power Piping Code (Reference 7), requires that loads used to calculate pipe stresses be generated with the pipe elastic modulus taken at the cold condition temperature. Table 5.2-9A establishes the code of record for all RCS components. Linear coefficients of thermal expansion, in terms of inches per foot, are input for all model elements, including the supports.

The support/restraint scheme used for this load case is the same as that used for the pressure expansion load case (see Section 3B.5.2).

3B.5.7 Seismic

Two seismic load cases were analyzed:

1. Operating Basis Earthquake (OBE).
2. Safe Shutdown Earthquake (SSE). This earthquake is also known as the Design Basis Earthquake (DBE).

The seismic analyses considered modes up to the cutoff frequency of 35 Hertz, although missing mass effects were considered to approximate the contribution of the higher frequency modes.

Consistent mass was used to represent the RCS piping and the majority of the component weights. Lumped mass was used to represent the CRDMs and their support structure, the SG primary and secondary heads, the whip restraints on the XOL and the splitter in the XOL elbow nearest the RCP.

Subregional modal (non-proportional) damping was used in the seismic analyses. In this method each section in the mathematical model is assigned a frequency dependent damping value as follows:

- Damping used for the model sections representing the RCS piping is 1/2% for OBE and 1% for SSE per Section 3.7.1.2

- Damping for the model sections representing the RCS components is 1/2% for OBE and 1% for SSE per Section 3.7.1.2

- Damping for the model sections representing welded steel structures (supports/restraints) is 1% for OBE and 3% for SSE per Section 3.7.1.3

- Damping for the model sections representing bolted structures (RV sliding supports, SG upper support snubbers and sliding bumper, RCP motor/motor stand) is 2.5% for OBE and 5% for SSE per Section 3.7.1.3

- Damping for the model sections representing reinforced concrete structures (the RV cavity wall) is 2% for OBE and 5% for SSE per Section 3.7.1.3

Composite damping for each mode considered is calculated by relating it to the relative strains of each of the model sections.

Once the composite damping for a mode is calculated, the spectral acceleration to be applied at the fixed support nodes is selected from the appropriate input spectra curves. The three response spectra acting in the directions of the global coordinate axes are input at several damping values. If the damping for a mode falls between two of the input spectra curves (as is the case most often) the bounding spectra curves are interpolated to get the correct spectral acceleration. Log-linear Interpolation is used since the input spectral curves are log-linear.

The seismic analyses are performed as enveloped spectra analyses, that is, the building response spectra at the highest support point for the RCS Is applied at all support points Including basemat. The highest support point is the 130′ elevation where the SGUS connects to the floor. The response spectra at 130′ was visually compared to that at 97′, the other elevation where the RCS is tied to the wall (by the RV support). In the frequency range of interest (4.5 to 35 Hz) and for the damping values shown above, this comparison indicated that the 130′ spectra envelopes the 97′. Note that the horizontal stays between the SGLS and the reactor cavity wall and between the RCP support and the reactor cavity wall are not active for seismic analysis, as was noted above.

Results (displacements, loads) were generated for each structural mode below 35 Hz. These modal results were combined considering closely spaced modes: those modes with frequencies that were within 10% of the frequency of the lowest mode in the group were combined per the 10% method as described in Regulatory Guide 1.92 (Reference 8) and were then combined by SRSS with the remainder of the modes. The Ten Percent Method is conservative relative to the method used in the original design basis analysis as described in Section 3.7.3.3.

The model responses to the directional earthquake Input (applied response spectra) were combined two-dimensionally and the maximum of the X+Y and Y+Z earthquake combination is reported in the analysis output.

Seismic Anchor Motions (SAMs) were not considered in the analysis of the Salem RCS because the differences in motion between the containment building at the RV support elevation and basemat and between the containment floor at the SGUS elevation and basemat are so small that they would have negligible effect on the pipe and support stresses. The magnitude of the SAM's used to reach this conclusion were calculated from information contained in Volume 1 of the report describing the Conrad analysis of the Salem containment buildings (Reference 9).

The component horizontal restraints are shimmed such that there is the potential for small gaps when the system reaches 100% power. Because of these gaps at hot condition. the radial restraints at the RCP support lugs, at the SG lower support lugs and at the SG upper support bumpers will not be active when the RCS reaches 100% power conditions. However, under seismic excitation, oscillation of the SG will cause at least two of the SG lower support radial bumpers and the upper support bumper to become active. Additionally, oscillation of the RCP will cause at least one of the RCP radial bumpers to become active. Therefore, two SG lower support radial bumpers, the SG upper support bumper and one of the RCP radial bumpers were considered active in the seismic analyses. Because it was not apparent which two SG lower support radial bumpers should be made active, two different adjacent bumpers were made active in each of the four loops. Similarly, because it was not apparent which RCP radial bumper should be made active, three different ones were made active amongst the four loops (two loops will have the same RCP radial bumper active). Given the symmetry of the RCS geometry, one of the four loops will give bounding results under this approach.

The RV supports are not designed to resist loads radial to the RV centerline and so are not active in that direction. The SG upper support snubbers are active for the seismic load cases.

The tangential restraints at the RV support pads and at the RCP and SG support lugs are considered active for the seismic load cases because they are two-way restraints (there is a bumper on either side of the pad/lug in the tangential direction). Because the tangential restraints are two-way, one or the other side will be in contact and the tangential restraints were therefore made active.

The horizontal stays which tie the RCP and SG lower supports to the RV cavity wall are considered inactive for the seismic analyses. This will lead to conservative results in the remainder of the RCS.

3B.5.8 High Energy Line Break Accident (HELBA)

Seven high energy line break cases were analyzed:

1. Main Steam Line Break. This secondary side break is postulated at the main steam line connection to the SG nozzle.

2. Feedwater Line Break. This secondary side break is postulated at the feedwater line connection to the SG nozzle.

3. Surge Line Break. This primary side break is postulated at the surge line connection to the hot leg nozzle.

4. Intermediate Surge Line Break. This primary side break is postulated at the downstream end of the surge line elbow nearest the hot leg.

5. 14" Residual Heat Removal Line Break. This primary side break is postulated at the 14" RHR line connection to the hot leg nozzle.

6. 6" Residual Heat Removal Line Break. This primary side break is postulated at the 6" RHR line connection to the hot leg nozzle.

7. Safety injection Line Break. This primary side break is postulated at the SI connection to the cold leg nozzle.

The effects on the RCS of smaller breaks are enveloped by these seven breaks.

The HELBA analyses considered modes up to the cutoff frequency of 100 Hertz, although missing mass effects were considered to approximate the contribution of the higher frequency modes.

The initial conditions for the HELBA analyses are set such that the initial (time zero) displacements are 0.0. This will make the input forcing functions act as impact loads initially.

Consistent mass was used to represent the RCS piping and the majority of the component weights. Lumped mass was used to represent the CRDMs and their support structure, the SG primary and secondary heads, the ship restraints on the crossover leg and the splitter in the crossover leg elbow nearest the RCP. In addition, a rotational mass moment of inertia was input for the RV, RCP assembly and SG since the analysis code does not calculate this term for those model sections having their cross sections defined by an outside diameter and the thickness, that is, for those cross sections modeled as pipe.

Subregional modal (non-proportional) damping was used in the HELBA analyses. In this method each section in the mathematical model is assigned a frequency dependent damping:

- Damping used for the model sections representing the RCS piping was 1%.
- Damping for the model sections representing the RCS components was 1%.
- Damping for the model sections representing welded steel structures (supports/restraints) was 3%.
- Damping for the model sections representing bolted structures (RV sliding supports, SG upper support snubbers and sliding bumper, RCP motor/motor stand) was 5%.
- Damping for the model sections representing reinforced concrete structures (the RV cavity wall) was 5%.

Composite damping for each mode considered is calculated by relating it to the relative strains of each of the model sections.

The primary pipe break loading consists of the following time history forcing functions: loop internal forcing functions, ACPs, thrust forces and JI (where applicable). The secondary pipe break loading consists of the following time history forcing functions: SG internal pressure differentials, ACPs, thrust forces and JI (where applicable). The dynamic response of the RCS model to these excitations was calculated using the modal superposition method with piecewise linear integration.

Note that an SSE load case was run with each of the HELBA load cases. The results from the "concurrent" HELBA and SSE are combined by the Square-Root-Sum-of-the-Squares (SRSS) method, for use in the pipe and SG lower support stress calculations, per Section 3.9.1.6. The concurrent SSE uses the same restraint activity scheme as its corresponding HELBA case and therefore the most conservative combination of loads on the modified SG lower support columns is assured. Note that the damping used in these HELBA/SSE analyses is equivalent to that used for SSE alone.

The component horizontal restraints are shimmed such that there is the potential for small gaps when the system reaches 100% power. Because of these gaps at hot condition, the radial restraints at the RCP support lugs, at the SG lower support lugs and at the SG upper support bumpers will not be active when the RCS reaches 100% power conditions. However1 under HELBA excitation, oscillation of the SG will cause at least two of the SG lower support radial bumpers and the upper support bumper to become active. Additionally, oscillation of the RCP will cause at least one of the RCP radial bumpers to become active.

Note that it is highly likely that two of the RCP radial bumpers will be active since the resultant movement of the RCP must be exactly along the axis of one of the radial bumpers in order for only that bumper to be active. Therefore, considering only one of the radial bumpers active for the HELBA load cases will lead to conservative results on one of the "columns" under the RCP lugs. The load in the rest of the loop is largely unaffected by the number of radial bumpers made active on the RCP because the line of action for each of the radial bumpers is also a line of action for the tangential restraints. This means that when one radial bumper is active, two other tangential bumpers are also active and so the RCP load gets distributed around the RCP support. Because it is not apparent which RCP radial bumper should be made active, three different ones will be made active amongst the four loops (two loops will have the same RCP radial bumper active). The RCP radial bumper activity used in the HELBA analyses is the same as that used for the seismic analyses.

The RV supports are not designed to resist loads radial to the RV centerline and so are not active in that direction. The SG upper support snubbers are active for the HELBA load cases. The tangential restraints at the RV support pads and at the RCP and SG support lugs are considered active for the HELBA load cases because they are two-way restraints (there is a bumper on either side of the pad/lug in the tangential direction). Because the tangential restraints are two-way, one or the other side will be in contact and the tangential restraints were therefore made active.

The RV restraint activity is the same for all load cases. The SG upper support radial bumpers (and snubbers) are represented as snubbers in the model which means that they are active for the dynamic (seismic) and time history (HELBA) load cases. The determination of the SG lower support radial bumper activity and the RCP and SG lower support horizontal stay activity Is determined in an iterative analysis as outlined below:

1. Each pipe break load case was evaluated assuming the one-way restraints are inactive and relative motions between the components and one-way restraints are determined. The RCP and SGLS radial bumpers and the gapped members between the RV cavity wall and the RCP and SG lower supports are considered one-way restraints;

2. Based on the magnitude and direction of relative motions between the component lug and the support, it was decided which one-way restraints should be considered active and which should be considered inactive;

3. The restraint activity was adjusted according to the findings from Step 2 and the pipe break load case was re-executed.

4. Relative motions between the components and the inactive one-way restraints were reviewed to confirm that the appropriate restraint scheme was used. If so, the analysis for that break was complete. If the restraint scheme was not correct, the process was iterated starting at step 2.

3B.6 Stress Analyses

FTI's stress analysis computer code, BWSCAN, was used to calculate RCS pipe stresses as well as stresses in the SGLS members. BWSCAN is a subprogram of the FTI piping/structural computer code, BWSPAN (see Section 3B.9). In addition to the calculations performed by BWSCAN, a detailed stress analysis of the modified SG columns was performed using FTI's finite element analysis code, HPE (see Section 3B.9), and hand calculations.

3B.6.1 RCS Pipe Stress Analysis

BWSCAN analyzes B31.1 piping to the 1980 Edition of ANSI B31.1, "Power Piping" (Reference 10). The code of record for the Unit I RCS piping is the 1955 edition of the ASA B31.1 Power Piping Code (see Table 5.2-9A). However, the original design basis analysis of the RCS performed by Westinghouse was intended to cover both units and so was done to the 1967 Edition of B31.1 (Reference 11) which is the code of record for the Unit 2 RCS piping (see Table 5.2-9b). The code equations from these three editions of B31.1 were compared and it was concluded that of the three code years, the 1980 Edition B31.1 will result in the most conservative stresses. Therefore, use of the 1980 Edition B31.1 to calculate RCS pipe stresses was shown to be acceptable.

The stress allowables used for the RCS piping were taken from ASA Code Cases N-7 and N-10, per Table 5.2-9A, at 100% power normal operating temperatures. The service factor applied to these allowables for upset condition load combinations (1.2) was taken from Table 5.2-13. The service factor given in Table 5.2-13 for emergency condition load combinations (1.8) was conservatively applied to the allowables for use with the faulted load combinations.

3B.6.2 SG Lower Support Stress Analysis

BWSCAN analyzes structural steel to Subsection NF of Section III to the 1986 Edition of the ASME B&PV Code (Reference 12). The stress calculations it performs are limited to axial, shear, bending and combined axial and bending stresses acting on the gross section of the structural steel members. The

Salem structural design criteria allows the use of any edition of the AISC Specification for the Design, Fabrication and Erection of Structural Steel, after the 6th edition, in the design of Class I structures. Comparison of the equations used in the BWSCAN analysis to those in the 9th Edition AISC Manual (Reference 13) shows that they are the same. Therefore, use of BWSCAN to calculate support steel stresses was shown to meet the criteria of the 9th Edition AISC Manual.

Allowable stresses were taken from the AISC Manual and confirmed through the original PSE&G sizing calculations for the SGLS. The service factor given in Table 5.5-3 for upset condition load combinations (1.33) was applied to the allowables for use with both the upset and faulted load combinations.

Welds connecting the various beams and columns making up the lower support were also qualified through stress analysis of the limiting weld location. The allowable shear stress was calculated per the, 9th Edition AISC Manual with appropriate service factors.

The stress analysis of the modified SG columns was performed by finite element analysis and by hand using the equations given in the 9th Edition AISC Manual and design loads developed from preliminary results of the RCS analysis. All components of the columns were analyzed, including the welds between the various pieces making up the column and the column attachment welds. The design loads used were compared to the column loads from the final RCS analysis and were found to be bounding.

Allowable stresses for the modified SG column material were taken from the , 9th Edition AISC Manual. Appropriate service factors were used.

3B.6.3 RCP Support Stress Analysis

Stresses in the RCP support members were calculated in the same manner used by Westinghouse in the original design basis analysis: total support load was converted to member loads through the member influence coefficient matrices which were in turn used to calculate member stresses. Stress allowables were calculated per the 7th Edition AISC Manual (Reference 14). Conservatively, no service factor was applied to the upset condition stress allowables and the service factor used for the faulted condition stress allowables was that given in Table 5.5-3 for the upset condition.

Welds connecting the various beams and columns making up the RCP support were also qualified through stress analysis of the limiting weld location. The allowable shear stress was calculated per the 7th Edition AISC Manual with appropriate service factors.

3B.7 Analysis Results/RCS Qualification

To ensure that the design basis of the RCS components is not violated, the component nozzle and support lug (ring) loads were compared to the existing loads/stresses from the original design basis:

- The RV primary nozzle loads/stresses were compared to those given in the Westinghouse Equipment Specification for the Salem RV's and were shown to be acceptable.

- The SG primary nozzle loads/stresses and upper support reaction loads/stresses were compared to those given in the Westinghouse stress report for the Model F SGs and were shown to be acceptable.

- The SG support ring loads were compared to those given in the Westinghouse stress report for the Model F SGs. The FTI analyses generated tangential load on the support ring which was not considered In the Westinghouse stress report The support ring was qualified for this tangential load by FTI.

- The SG upper support loads were compared to those generated in the original design basis analysis of the RCS performed by Westinghouse. The loads are less than those generated In the original design basis analysis.

- The RCP primary nozzle and support lug reaction loads/stresses were compared to those given in the Westinghouse Equipment Specification for the Salem RCPs and were shown to be acceptable.

- The RV support loads were compared to those given in the Westinghouse Equipment Specification for the Salem RVs. Where individual loads or load combinations were higher than those given In the equipment specification the resulting stress increase was shown to be negligible based on information given in the PSE&G analysis of the support.

- SG lower support member stress ratios were calculated as outlined above. All SGLS member stress ratios were shown to be less than 1.0. The limiting partial penetration beam-to-column weld was stress analyzed and was shown to meet the appropriate stress criteria. In addition, a detailed analysis of the modified SG columns shows that all appropriate stress criteria are met.

- RCP support member stress ratios were calculated as outlined above. All member stress ratios were shown to be 1.0 or less. The limiting partial penetration beam-to-column weld was stress analyzed and was shown to meet the appropriate stress criteria.

- Leak-Before-Break (LBB) load combinations, at selected (enveloping) locations, were compared to those given in the Westinghouse topical report on LBB (Reference 15). Locations where normal stresses were lower or faulted stresses were higher than those in the topical report were shown to be acceptable based on available LBB margins as described in the topical report and the NRC's SER on the subject (Reference 1).

in order to qualify the RCS piping, stresses were calculated and compared to allowable stresses as outlined above. All RCS pipe stresses were shown to be less than the appropriate allowable stresses.

Table 3B.7-1 presents the methods used to qualify the various parts of the RCS in a tabular format. Tables 3B.7-2, 3B.7-3 and 3B.7-4 present summaries of the highest calculated SG lower support, RCP support and RCS pipe stress ratios.

3B.8 Conclusions

The FTI analysis of the Salem Unit 1 RCS, with the Model F SG, has demonstrated that the RCS piping, components and component supports remain in compliance with design basis requirements. There are no Unreviewed Safety Questions (USQs) related to the adequacy of the RCS with the Model F SGs in the RCS.

3B.9 Computer Codes

The following computer codes were used in the FTI analysis of the Salem Unit 1 RCS:

BWHIST. "Force Evaluation and Pressure Integration"

IBWHIST can be used for two basic functions:

1. Calculating the force time histories acting on a component using CRAFT2 pressure time history output, or pressure time history data in a user defined format; and

2. Calculating the force time histories acting on a component using CRAFT2 force time history output.

When working with CRAFT2, or user input, pressure time history data, forces are generated by integrating the pressures over the user defined surfaces. In either case (pressure or force time history input), the output force time histories are oriented in the user defined global coordinate system. This is most often the global coordinate system being used for the structural model of the NSSS which simplifies the application of the force time histories to the structural model.

CRAFT2 pressure or force time history output can contain a large number of time steps. Because of this, the user can request that BWHIST perform a data reduction before the final force time histories are output. The data reduction is based on slope change, an increasing tolerance band on the peak load and the maximum time step requested. BWHIST can also be used to plot the input and output time histories.

BWSPAN/BWSCAN, "Linear Static and Dynamic Analysis Program"

BWSPAN is a finite element code designed to perform linear loading and stress

analyses of structural systems such as piping systems, their associated supports and "spring and mass" representations of building structures. The user defines model segments (line elements) between nodes in three dimensional space and assigns these elements appropriate material and cross section properties. Springs, stiffness/mass/damping matrices and user defined special cross sections can be input.

Static (deadweight, thermal expansion, pressure, seismic, concentrated forces and applied displacements), response spectrum (most often seismic) and time history (most often pipe break) loads can be applied. Applied loads or displacements are analyzed using standard matrix solution techniques. For response spectrum analysis, multi-support spectra or enveloping spectra can be applied. Time history solution can be by the Wilson-Theta method or by the piecewise linear method (gapped springs can be input when the piecewise linear method of solution is selected). For response spectrum and time history analysis, damping can be applied to each individual model segment as mass or modal (strain energy) weighted damping. The user can also apply one modal weighted damping the entire system. BWSPAN can also analyze the effects of thermal stratification on piping.

Results include displacements and model segment loads. The dynamic analyses also give system frequencies and mode shapes and node point accelerations. Maximum or time-for-time results can be obtained for time history analyses. Superelement matrices can be generated for selected groups of model segments also.

BWSCAN is the stress analysis module of BWSPAN. It can perform Class 1, 2 and 3 pipe stress analyses to several editions of the ASME Boiler and Pressure Vessel Code, to the 1969 B31.7 Nuclear Power Piping Code and to the 1980 ANSI B31.1 Power Piping Code. Stress analysis of linear type supports can be performed to Subsection NF of Section III to the 1986 Edition of the ASME Boiler and Pressure Vessel Code.

COMPAR2, "A Code for the Transient Analysis of Volumes with Heat Sinks, Flowing Vents and Doors"

This computer program was developed to perform transient subcompartment pressure response analysis of nuclear power plant containments, Including those with ice condensers. The subcompartments are represented as volumes that are connected by Junctions and may have blowdown. The volume thermodynamics and flow equations are for a homogenous mixture, assumed to be in thermodynamic equilibrium, consisting of any one, or any combination of: a) steam, b) two-phase water to its triple point, and c) any three perfect gases such as air, helium, etc. Flow between volumes can be based on: a)

compressible (polytropic or isentropic) orifice flow of an ideal gas-like mixture that can be used to approximate the homogeneous equilibrium flow model, b) Moody flow with an arbitrary multiplier, and c) a one-dimensional solution of the momentum equation that includes an accounting for the effects of inertia. Variable area doors and heat sinks can also be modeled.

CRAFT2, "FORTRAN Program for Digital Simulation of a Multinode Reactor Plant During Loss of Coolant"

The CRAFT2 computer program was developed to study the transient behavior of a Nuclear Steam Supply System (NSSS) undergoing a Loss-of-Coolant Accident (LOCA). The program solves the conservation equations for mass and energy, the continuity equation and the equation of state for water.

The CRAFT2 program permits the user to select the nodal representation that results in The best finite differencing of the fluid system to be analyzed. The program then solves the interaction equations for each node and the momentum equation for each flow path between nodes. CRAFT2 contains both implicit and explicit solution techniques which may be selected by the user. The NSSS is simulated by a series of nodes which are connected by flow paths. Components with different thermal-hydraulic characteristics must be simulated as different nodes.

CRAFT2 contains flexible models of all major NSSS components.
Various options as well as user input allow the program to model the reactor core, reactor coolant pumps, steam generators and connected piping in any configuration and operating mode desired. The diversity of the models also allows the program to accurately model any thermal-hydraulic system containing similar components.

HPE, "2D & 3D Finite Element Analysis Program for Microcomputers"

HPE performs static and dynamic stress analysis and steady state and transient heat transfer analysis of two and three dimensional finite element models. The element library is composed of truss, beam, spring, plate, solid and gap elements. The analysis system consists of a pre-processor, for inputting the model, analysis modules for static, dynamic and thermal analysis, and a post-processor. HPE uses standard techniques of finite element analysis for solution.

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SECTION 4

REACTOR

4.1 SUMMARY DESCRIPTION

This chapter describes the following: 1) the mechanical components of the reactor and reactor core including the fuel rods and fuel assemblies, reactor internals, and the control rod drive mechanisms, 2) the nuclear design, and 3) the thermal-hydraulic design.

The reactor core is comprised of an array of fuel assemblies which are similar in mechanical design and fuel enrichment. The Salem Unit 1 and 2 cores may consist of any combination of fuel designs including standard (STD), Vantage 5H, Vantage+, and standard Robust Fuel Assembly (RFA) as described in Section 4.2.1.2. The most significant difference between the Vantage+ and RFA fuel and the others is the application of Zirlo™ cladding, guide thimble and instrument tubes. The Vantage+ and RFA are modifications of the NRC-approved Vantage 5H fuel assembly design (Reference 1). A detailed description and evaluation of the Vantage+ and RFA features is provided in References 2, 4 and 5.

The core is cooled and moderated by light water at a pressure of 2250 psia in the Reactor Coolant System. The moderator coolant contains boron as a neutron absorber. The concentration of boron in the coolant is varied as required to control relatively slow reactivity changes including the effects of fuel burnup. Additional boron, in the form of burnable absorber rods and/or IFBAs, may be employed in the core to establish the desired initial reactivity.

Two hundred and sixty-four fuel rods are mechanically joined in a square array to form a fuel assembly. The fuel rods are supported in intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. The grid assembly consists of an "egg-crate" arrangement of interlocked straps. The straps contain spring fingers and dimples for fuel rod support as well as coolant mixing vanes. The fuel rods consist of slightly enriched uranium dioxide ceramic cylindrical pellets contained in slightly cold worked Zircaloy-4 or Zirlo ™ tubing which is plugged and seal welded at the ends to

encapsulate the fuel. All fuel rods are pressurized with helium during fabrication to reduce stresses and strains and to increase fatigue life. In addition, the Zirlo™ fuel rods may be oxide coated at the lower end for additional protection against fretting. RFA fuel rods will utilize annular pellets at the top and bottom 6" to provide lower rod internal pressures.

The center position in the assembly is reserved for the in-core instrumentation, while the remaining 24 positions in the array are equipped with guide thimbles joined to the grids and the top and bottom nozzles. Depending upon the position of the assembly in the core, the guide thimbles are used as core locations for rod cluster control assemblies, neutron source assemblies, and burnable absorber rods. The remaining guide thimbles may be fitted with plugging devices to limit bypass flow. The use of plugging devices is optional.

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly.

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the rod cluster control assembly or other core components.

The rod cluster control assemblies each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. These assemblies have rods containing absorber material to control the reactivity of the core under operating conditions.

The control rod drive mechanisms are of the magnetic latch type. The latches are controlled by three magnetic coils. They are so designed that upon a loss of power to the coils, the rod cluster control assembly is released and falls by gravity to shut down the reactor.

The components of the reactor internals are divided into three parts consisting of the lower core support structure (including

the entire core barrel and thermal shield), the upper core support structure and the in-core instrumentation support structure. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between the fuel assemblies and control rod drive mechanisms, direct coolant flow past the fuel elements and to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the in-core instrumentation.

The nuclear design analyses and evaluation establish physical locations for control rods and burnable absorbers, and physical parameters such as fuel enrichments and boron concentration in the coolant such that the reactor core has inherent characteristics which, together with corrective actions of the Reactor Control, Protection and Emergency Cooling Systems provide adequate reactivity control even if the highest reactivity worth rod cluster control assembly is stuck in the fully withdrawn position. The design also provides for inherent stability against diametral and azimuthal power oscillations.

The thermal-hydraulic design analyses and evaluation establish coolant flow parameters which assure that adequate heat transfer is assured between the fuel cladding and the reactor coolant. The thermal design takes into account local variations in fuel rod dimensions, power generation, flow distribution, and mixing. The mixing vanes incorporated in the fuel assembly spacer grid design induces additional flow mixing between the various flow channels within a fuel assembly as well as between adjacent assemblies.

Instrumentation is provided in and out of the core to monitor the nuclear, thermal-hydraulic, and mechanical performance of the reactor and to provide inputs to automatic control functions.

The reactor core design together with corrective actions of the Reactor Control, Protection and Emergency Cooling Systems can meet the reactor performance and safety criteria specified in Section 4.2.

To illustrate the effects of the change in fuel design, Table 4.1-1 presents principal nuclear, thermal-hydraulic, and mechanical design parameters for the Salem 17 x 17 STD, Vantage 5H, Vantage+, and RFA fuel assemblies.

The effects of fuel densification were evaluated(1).

The analytical techniques employed in the core design are tabulated in Table 4.1-2. The loading conditions considered in general for the core internals and components are tabulated in Table 4.1-3. Specific or limiting loads considered for design purposes of the various components are listed as follows: fuel assemblies in Section 4.2.1.1.2; reactor internals in Section 4.2.2.3 and Table 5.1-10; neutron absorber rods, burnable absorber rods, neutron source rods, and thimble plug assemblies (if used) in Section 4.2.3.1.3; control rod drive mechanisms in Section 4.2.3.1.4.

4.1.1 Reference for Section 4.1

1. Davidson, S.L. (Ed.), et al., "Vantage 5H Fuel Assembly Reference Core Report," WCAP-10444-P-A and Appendix A, September 1985; Addendum 2-A, March 1986; Addendum 2-A, April 1988.

2. Davidson, S.L., Nuhfer, D.L. (Eds.), "Vantage+ Fuel Assembly Reference Core Report," WCAP-12610-P-A, April 1995.

3. Hellman, J. M. (Ed.), "Fuel Densification Experimental Results and Model for Reactor Application," WCAP-8218-P-A (Proprietary) and WCAP-8219-A (Nonproprietary), March 1975.

4. Letter from W.J. Rinkacs (Westinghouse) to M.M. Mannion (PSE&G), "Westinghouse Fuel Features Recommendation for Cycle 11", July 22, 1998.

5. Letter from W.J. Rinkacs (Westinghouse) to M.M. Mannion (PSE&G), "Westinghouse Generic Safety Evaluation for the 17x17 Standard Robust Fuel Assembly", October 1, 1998.

4.2 MECHANICAL DESIGN

The plant conditions for design are divided into four categories in accordance with their anticipated frequency of occurrence and risk to the public: Condition I - Normal Operation; Condition II - Incidents of Moderate Frequency; Condition III - Infrequent Incidents; Condition IV - Limiting Faults.

The reactor is designed so that its components meet the following performance and safety criteria:

1. The mechanical design of the reactor core components and their physical arrangement, together with corrective actions of the Reactor Control, Protection, and Emergency Cooling Systems (when applicable) assure that:

   a. Fuel damage* is not expected during Condition I and Condition II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the Plant Cleanup System and are consistent with the plant design bases.

   b. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged* although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

   c. The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

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* Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod clad).

2. The fuel assemblies are designed to accommodate expected conditions for design for handling during assembly inspection and refueling operations and shipping loads.

3. The fuel assemblies are designed to accept control rod insertions in order to provide the required reactivity control for power operations and reactivity shutdown conditions.

4. All fuel assemblies have provisions for the insertion of in-core instrumentation necessary for plant operation.

5. The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements can be met for all modes of operation. In addition, the internals provide core support and distribute coolant flow to the pressure vessel head so that the temperature differences between the vessel flange and head do not result in leakage from the flange during the Condition I and II modes of operation. Required inservice inspection can be carried out as the internals are removable and provide access to the inside of the pressure vessel.

4.2.1 Fuel

4.2.1.1 Design Bases

The fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 and specific criteria noted below. The same design bases apply to the 17 x 17 standard (STD), 17 x 17 Vantage 5H, 17 x 17 Vantage+ and 17 x 17 Standard Robust Fuel Assembly (RFA) designs.

The stress limits for the austenitic steel components follow:

Stress Intensity Limits

Categories	Limit
General Primary Membrane Stress Intensity	Sm
Local Primary Membrane Stress Intensity	1.5 Sm
Primary Membrane plus Bending Stress Intensity	1.5 Sm
Total Primary plus Secondary Stress Intensity	3.0 Sm

The Zircaloy and ZIRLO™ structural components which consist of guide thimble and fuel tubes are in turn subdivided into two categories because of material differences and functional requirements. The fuel tube design criteria are covered separately in Section 4.2.1.1.1. The maximum stress theory is used to evaluate the guide thimble design. The maximum stress theory assumes that yielding due to combined stresses occur where one of the principal stresses are equal to the simple tensile or compressive yield stress. The Zircaloy and ZIRLO™ unirradiated properties are used to define the stress limits.

Abnormal loads during Conditions III and IV - worst case represented by combined seismic and blowdown loads.

1. Deflections of components cannot interfere with the reactor shutdown or emergency cooling of the fuel rods.

2. The fuel assembly component stresses under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME Pressure Vessel Code Section 3. Since the current analytical methods utilize elastic analysis, the stress allowables are defined as the smaller value of 2.4 Sm or 0.70 Su for primary membrane and 3.6 Sm or 1.05 Su for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in

accordance with the rules described in the previous section for normal operating conditions. For the Zircaloy and ZIRLO™ components the stress limits are set at two-thirds of the material yield strength, Sy, at reactor operating temperature. This results in Zircaloy stress intensity limits being the smaller of 1.6 Sy or 0.70 Su for primary membrane and 2.4 Sy or 1.05 Su for primary membrane plus bending. For conservative purposes, the Zircaloy and ZIRLO™ unirradiated properties are used to define the stress limits. The grid component strength criteria are based on experimental tests. The grid component strength criterion is based on the lower 95 percent confidence level on the true mean from distribution of grid crush strength data at temperature.

4.2.1.2 Design Description

Fuel assembly and fuel rod design data are given in Tables 4.1-1 and 4.3-1. Two hundred sixty-four fuel rods, twenty-four guide thimble tubes, and one instrumentation thimble tube are arranged within a supporting structure to form a fuel assembly. The instrumentation thimble is located in the center position and provides a channel for insertion of an in-core neutron detector if the fuel assembly is located in an instrument core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a neutron source assembly, a burnable absorber assembly or a plugging device (if used), depending on the position of the particular fuel assembly in the core. Figure 4.2-1 shows a cross section of a fuel assembly array, and Figure 4.2-2 shows a standard fuel assembly full length view. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles.

The design changes from the 17 x 17 STD design to the Vantage 5H design include reduced guide thimble and instrumentation tube diameters, and replacement of the six intermediate (mixing vane) Inconel grids with Zircaloy grids. The debris filter bottom nozzle (DFBN) design has been incorporated into the Vantage 5H fuel assembly. The DFBN is similar to the standard bottom nozzle design except that it is thinner and has a new pattern of smaller flow holes. The DFBN helps to minimize passage of debris particles that could cause fretting damage to fuel rod cladding.

The Vantage+ assembly skeleton is identical to that previously described for Vantage 5H except for those modifications necessary to accommodate intended fuel operation to higher burnup levels. The Vantage+ assembly skeleton is made of low cobalt material and the spring height is slightly increased for the reduction in fuel assembly height. The modifications consist of the use of ZIRLO™ guide thimbles as necessary, and small skeleton dimensional alterations to provide additional fuel assembly and rod growth space at the extended burnup levels. The Vantage+ fuel assembly is 0.200 inch shorter than the Vantage 5H assembly. The grid centerline elevations of the Vantage+ are identical to those of the Vantage 5H assembly, except for the top grid. The Vantage+ top grid has been moved down by the same 0.200 inch. The RFA assembly provides further design enhancements from the Vantage+ design including modified Low Pressure Drop mid-grids and IFMs, thicker guide tubes, and a protective bottom grid. The RFA continues to utilize the ZIRLO™ fuel rods and skeletons. However, since the Vantage+ and RFA fuel are intended to replace either the Westinghouse LOPAR or Vantage 5H, their assembly exterior envelope is equivalent in design dimensions, and the functional interface with the reactor internals is also equivalent to those of previous Westinghouse fuel assembly designs. Also, the Vantage+ and RFA are designed to be mechanically and hydraulically compatible with the LOPAR and Vantage 5H, and the same functional requirements and design criteria as previously established for the Westinghouse Vantage 5H fuel assembly remain valid for the Vantage+ and RFA (References 18, 21). The Vantage+ and RFA design parameters are provided in Table 4.1-1. Figure 4.2-2A compares the Vantage+ and the Vantage 5H fuel assembly designs. The RFA design is shown in Figure 4.2-2B.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears downward against the fuel assembly top nozzle via the holddown springs to hold the fuel assemblies in place.

4.2.1.2.1 Fuel Rods

The Vantage+ and RFA fuel rod designs represent a modification to the Vantage 5H fuel rod in cladding of ZIRLO™ as compared to Zircaloy-4. ZIRLO™ is a zirconium alloy similar to Zircaloy-4, which has been specifically developed to enhance corrosion resistance. The Vantage 5H, Vantage+, and RFA fuel rods contain enriched uranium dioxide fuel pellets, and Integral Fuel Burnable Absorber (IFBA) coating on some of the fuel pellets. Additionally, the RFA fuel rods contain axial blankets (top and bottom 6 inches) of annular pellets. The annulus represents a 25% void by volume of the pellet. Schematics of the fuel rods are shown in Figures 4.2-3, 4.2-3A, and 4.2-3B.

The Vantage+ and RFA fuel rods have the same wall thickness as the Vantage 5H. The Vantage+ fuel rod length is shorter to provide the required fuel rod growth room. To offset the reduction in plenum length the Vantage+ fuel rod has a variable pitch plenum spring. The variable pitch plenum spring provides the same support as the Vantage 5H plenum spring, but with less spring turns which means less spring volume. The RFA fuel rod is longer than the Vantage+ and Vantage 5H designs but maintains sufficient room for fuel rod growth. This provides additional plenum length to accommodate fission gas release associated with high burnup. In addition, the RFA utilizes the variable pitch plenum spring and axial blankets of annular pellets to provide additional plenum margin. The 6 inches (top and bottom) of annular pellets effectively provide 3 additional inches of plenum volume beyond the current VANTAGE+ design. The bottom end plug has an internal grip feature to facilitate rod loading on the Vantage+, RFA, and Vantage 5H designs and provides appropriate lead-in for the removable top nozzle reconstitution feature. The RFA design also incorporates the external grip top end plug into its fuel rod design. This feature provides additional capability to reposition the fuel during manufacturing and will simplify reconstitution of the fuel rod from the top of the assembly. The Salem Vantage+ fuel rods also have an oxide coating at the bottom end. This extra layer of oxide coating provides additional rod fretting wear protection. The RFA design incorporates the protective bottom grid and modified fuel rod bottom end plug. These enhanced debris mitigating features, described in Section 4.2.1.2.2, diminish the need for the oxide coating. Therefore, for core designs utilizing the RFA, the oxide coating may be incorporated as an option to be determined on a reload basis.

The Salem Vantage 5H, Vantage+, and RFA fuel uses a standardized fuel pellet design which is a refinement to the chamfered pellet design. The standard design helps to improve manufacturability while maintaining or improving performance (e.g., improved pellet chip resistance during manufacturing and handling).

The Vantage 5H, Vantage+, and RFA IFBA coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride

coating on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of IFBA rods within an assembly vary depending on specific application. The ends of the coated and uncoated pellets are dished to allow for greater axial expansion at the pellet centerline and void volume for fission gas release. To accommodate a six inch axial blanket length at the top and bottom of the Robust Fuel Assembly (RFA) fuel rods, the annular pellets have a longer length than the solid pellets to obtain an integer number of fuel pellets which will equal a six inch length.

To avoid overstressing of the cladding or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel density changes during burnup. Shifting the fuel within the cladding during handling or shipping prior to core loading is prevented by a stainless steel helical spring which bears on top of the fuel. At assembly the pellets are stacked in the cladding to the required fuel height, the spring is then inserted into the top end of the fuel tube and the end plugs pressed into the ends of the tube and welded. All fuel rods are internally pressurized with helium during the welding process in order to minimize compressive clad stresses and creep due to coolant operating pressures. Fuel rod pressurization is dependent on the planned fuel burnup as well as other fuel design parameters and fuel characteristics (particularly densification potential).

4.2.1.2.2 Fuel Assembly Structure

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles, and grids, as shown on Figures 4.2-2 and 4.2-2A.

Bottom Nozzle

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The square nozzle is fabricated from Type 304 stainless steel and consists of a perforated plate and four angle legs with bearing plates as shown on Figure 4.2-2. The legs form a plenum for the inlet coolant flow to the fuel assembly. The plate itself acts to prevent a downward ejection of the fuel rods from the fuel assembly. The bottom nozzle is fastened to the fuel assembly guide tubes by locked screws which penetrate through the nozzle and mate with an inside fitting in each guide tube.

The debris filter bottom nozzle (DFBN) design has been introduced into the Salem fuel assemblies to help reduce the possibility of fuel rod damage due to debris-induced fretting. The Vantage+ and RFA assemblies have a low cobalt

stainless steel DFBN. The DFBN design incorporates a modified flow hole size and pattern, as described below, and a decreased nozzle height and thinner top plate to accommodate the high burnup fuel rods. The DFBN retains the design reconstitution feature which facilitates easy removal of the nozzle from the fuel assembly.

The relatively large flow holes in a conventional bottom nozzle are replaced with a new pattern of smaller flow holes in the DFBN. The holes are sized to minimize passage of debris particles large enough to cause damage. The holes were also sized to provide sufficient flow area, comparable pressure drops, and continued structural integrity of the nozzle. Tests to measure pressure drop and demonstrate structural integrity have been performed to verify that the DFBN is totally compatible with the current design.

Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the penetrations in the plate to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

Axial loads (holddown) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing plates which mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

Top Nozzle

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the rod cluster control assembly or other components. It consists of an adapter plate, enclosure, top plate, and pads. The integral welded assembly has holddown springs mounted on the assembly as shown on Figure 4.2-2. The springs and bolts are made of Inconel 718 and Inconel 600, respectively, whereas other components are made of Type 304 stainless steel.

Vantage+, RFA, and Vantage 5H fuel assemblies use the reconstitutable top nozzle (RTN). The RTN design for the Vantage 5H fuel assembly differs from the conventional design in two ways: 1) a groove is provided in each thimble thru-

hole in the nozzle plate to facilitate attachment and removal, and; 2) the nozzle plate thickness is reduced to provide additional axial space for fuel rod growth. Additional details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in Section 2.3.2 in Reference 15.

The square adapter plate is provided with round and obround penetrations to permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves which are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is a sheet metal shroud which sets the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and are fastened in place by bolts and clamps located at two diagonally opposite corners. On the other two corners, integral pads are positioned which contain alignment holes for locating the upper end of the fuel assembly.

Guide and Instrument Thimbles

The guide thimbles are structural members which also provide channels for the neutron absorber rods, burnable poison rods, or neutron source assemblies. Each one is fabricated from Zircaloy-4 or ZIRLO™ tubing having two different diameters. The larger diameter at the top provides a relatively large annular area to permit rapid insertion of the control rods during a reactor trip as well as to accommodate the flow of coolant during normal operation. Four holes are provided on the thimble tube above the dashpot to reduce the rod drop time. The lower portion of the guide thimbles has a reduced diameter to produce a dashpot action near the end of the control rod travel during normal operation and to accommodate the outflow of water from the dashpot during a reactor trip. The dashpot is closed at the bottom by means of an end plug which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation. The top end of the guide thimble is fastened to a tubular insert by three expansion swages. The insert engages into the top nozzle and is secured into position by the lock tube. The lower end of the guide thimble is fitted with an end plug which is then fastened into the bottom nozzle by a locked screw.

Fuel rod support grids are fastened to the guide thimble assemblies to create an integrated structure. Since welding of the Inconel grid and Zircaloy thimble is not possible, the fastening technique depicted on Figures 4.2-5 and 4.2-9 is used for all but the top and bottom grids in a fuel assembly.

An expanding tool is inserted into the inner diameter of the Zircaloy or Zirlo TM thimble tube to the elevation of the zircaloy sleeves that have been welded to the Zircaloy middle grid assemblies. The four-lobed tool forces the thimble and sleeve outward to a predetermined diameter, thus joining the two components.

The top grid-to-thimble attachment for the Vantage 5H, Vantage+, and RFA design is shown on Figure 4.2-7. The Zircaloy or ZIRLO™ thimbles are fastened to the top nozzle inserts by expanding the members as shown on Figure 4.2-7. The inserts then engage the top nozzle and are secured into position by the insertion of lock tubes.

The bottom grid assembly is joined to the fuel assembly as shown on Figure 4.2-11. The stainless steel insert is spotwelded to the bottom grid and later captured between the guide thimble end plug and the bottom nozzle by means of a stainless steel thimble screw.

The described methods of grid fastening are standard and have been used successfully since the introduction of Zircaloy guide thimbles in 1969.

The central instrumentation thimble of each fuel assembly is constrained by seating in counterbores in each nozzle. This tube is a constant diameter and guides the incore neutron detectors. This thimble is expanded at the top and mid grids in the same manner as the previously discussed expansion of the guide thimbles to the grids.

With the exception of an increased length above the dashpot, the Vantage+ guide thimbles are identical to those in the Vantage 5H design. For the RFA, the thimble tube thickness has been increased by 25% (4 Mils) relative to the V5H and Vantage+ designs. The thimble tube outer diameter of both the upper spans (major diameter section above the dashpot) and the dashpot spans have been increased. The inner diameter of the thimble tube in both the upper spans and in the dashpot spans are unchanged from the current designs. With the thicker guide thimble tube, the cross-sectional area is increased by 26% in the major diameter section and 29% in the dashpot section. The Vantage+, RFA and Vantage 5H guide thimble ID provides adequate clearance for the control rods and sufficient diametral clearance for burnable absorber rods and source rods.

The Vantage+, RFA and Vantage 5H instrumentation tube diameter has sufficient diametral clearance for the flux thimble to traverse the tube without binding.

Grid Assemblies

The fuel rods, as shown on Figures 4.2-2, 4.2-2A and 4.2-2B, are supported laterally at intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is afforded lateral support at six contact points within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps interlocked and welded in an "egg-crate" arrangement to join the straps permanently at their points of intersection. The straps contain spring fingers, support dimples, and mixing vanes.

The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies also allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

Up to four types of grid types are used in each fuel assembly: Mid-grids (structural grids with flow mixing vanes), Intermediate Flow Mixing (IFM) grids (non-structural grids with flow mixing vanes), top and bottom structural grids without mixing vanes, and the protective bottom grid (P-grid). Table 4.1-1 provides the breakdown of the grid types, number and grid material used in each of the fuel designs. Flow mixing vanes project from the edge of the inner grid strap into the coolant stream to promote mixing of the coolant in the high heat flux regions of the fuel assembly.

The IFMs are positioned at the mid-spans of the four uppermost mid-grids to further increase the flow turbulence in the axial zone where departure from nucleate boiling (DNB) is limiting. Each IFM grid cell contains four dimples, which are designed to prevent mid-span channel closure in the spans containing IFMs and fuel contact with the mixing vanes.

For the RFA, the modified low pressure drop mid-grids and IFM grids are embossed to accept the larger diameter guide thimble tube.

The P-grid is a partial height grid similar in configuration to the mid-grid, but without mixing vanes. It is located between the bottom Inconel grid and the bottom nozzle, nearly on the surface of the bottom nozzle. The intersections of the inner straps of the P-grid align with the flow holes of the DFBN, effectively bisecting the flow path through the flow hole into four quarters. This provides an effective barrier against small debris. In conjunction with the P-grid, the fuel rod bottom end plug is changed to a longer design such that the portion of the fuel rod engaged in the P-grid and extending up past the top of the P-grid is solid end plug material. This provides a protective zone where trapped debris cannot fret through the fuel rod and cause a failure. The hydraulic effects of the P-grid are minimized by positioning the fuel rods 0.085 inches above the bottom nozzle. The combination of the lowered fuel rod position and longer fuel rod end plug results in no change to the axial fuel stack height from the previous Vantage+ fuel region.

For the application of the P-grid, the bottom Inconel grid is welded to 20 of the 24 inserts. The remaining four inserts are spot-welded to the P-grid at the four outermost corners on the grid diagonal.

The outside straps on all the grids contain mixing vanes which, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

During 1989, snag-resistant grids were introduced. These grids contain outer grid straps which are modified to help prevent assembly hangup from grid strap interference during fuel assembly removal. This was accomplished by changing the grid strap corner geometry and the addition of guide tabs on the outer grid strap.

design limits do not result in impairment of fuel assembly function.

Dimensional Stability

The Vantage 5H Mechanical Test Program description and results are given in Reference 16 and are considered to be applicable to Vantage+ as the two assemblies are structurally essentially identical.

The development of the RFA design included a comprehensive set of mechanical and hydraulic tests: pressure drop, assembly vibration, fuel rod vibration, bulge joint strength, grid crush. A description of these tests and results is provided in References 19, 20 and 21.

The coolant flow channels are established and maintained by the structure composed of grids and guide thimbles. The lateral spacing between fuel rods is provided and controlled by the support dimples of adjacent grid cells. Contact of the fuel rods on the dimples is assured by the clamping force provided by the grid springs. Lateral motion of the fuel rods is opposed by the spring force and the internal moments generated between the spring and the support dimples. Grid testing is discussed in Reference 10.

No interference with control rod insertion into thimble tubes will occur during a postulated loss-of-coolant accident (LOCA) transient due to fuel rod swelling, thermal expansion, or bowing. In the early phase of the transient following the coolant break, the high axial loads which potentially could be generated by the difference in thermal expansion between fuel clad and thimbles are relieved by slippage of the fuel rods through the grids. The relatively low drag force restraint on the fuel rods will only induce minor thermal bowing not sufficient to close the fuel rod-to-thimble tube gap. This rod-to-grid slip mechanism occurs simultaneously with control rod drop.

Vibration and Wear

The effect of the flow induced vibration on the V5H and Vantage+ fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The conclusion that the effect of flow induced vibrations on the fuel assembly and fuel rod is minimal is based on test results and analysis documented in Reference 11.

Full flow vibration tests have been performed on the RFA covering both assembly and fuel rod vibration. These tests have shown the Robust Fuel Design is not susceptible to flow induced assembly vibration and provides improved fuel rod vibration performance over the prior designs.

The reaction on the grid support due to vibration motions is also correspondingly small and much less than the spring preload. Firm contact is therfore maintained. No significant wear of the cladding or grid supports is expected during the life of the fuel assembly, based on out-of-pile flow tests, performance of similarly designed fuel in operating reactors (2), and design analyses.

Clad fretting and fuel rod vibration have been experimentally investigated as shown in Reference 11.

No significant guide thimble tube wear due to flow-induced vibration of the control rods is predicted. Based on a conservative wear analyses, Westinghouse concluded that the integrity of the guide tube is maintained during normal operation, accident conditions, and nonoperational loading condition for at least 250 weeks (> 3 cycles) of fuel assembly operation. The Nuclear Regulatory Commission (NRC) has concluded (12) that the Westinghouse analyses probably accounts for all the major variables in the wear process. However, the NRC requested additional confirmatory information supporting the absence of significant thimble wear (no wear hole formation) for the 17 x 17 fuel assembly design. Examination of 1434 guide thimble tubes in six fuel assemblies examined at Salem Unit 1 shows no wear hole formation. Four of the assemblies had control rods in the parked

position (7 1/2 inches into the guide thimble) for Cycle 1, and two assemblies had control rods parked for Cycles 1 and 2. The parked position of the control rods has the greatest potential for causing guide thimble wear due to flow induced vibrations. The results of this surveillance program satisfy the NRC request to verify the wear analysis conclusion of no wear holes.

Evaluation of the Reactor Core for Limited Displacement RPV Inlet and Outlet Nozzle Breaks

The STD fuel assembly response resulting from the most limiting main coolant pipe break was analyzed using time history numerical techniques. Since the resulting vessel motion induces primarily lateral loads on the reactor core, a finite element model similar to the seismic model described in Reference 10 was used to assess the fuel assembly deflections and impact forces.

The reactor core finite element model which simulates the fuel assembly interaction during lateral excitation consists of fuel assemblies arranged in a planer array with inter-assembly gaps. For the Salem Station, 15 fuel assemblies which correspond to the maximum number of assemblies across the core diameter were used in the mode. The fuel assemblies and the reactor baffle support are represented by single beam elements as shown on Figure 4.2-25. The time history motion for the upper and lower core plates and the barrel at the upper core plate elevation are simultaneously applied to the simulated reactor core model as illustrated on Figure 4.2-25. The three time history motions were obtained from the time history analysis of the reactor vessel and internals finite element model.

The fuel assembly response, namely the displacements and grid impact forces, were obtained from the reactor core model using the core plate and barrel motions resulting from a reactor coolant pump outlet double ended break. The maximum fuel assembly deflection which occurred in a peripheral fuel assembly was approximately 0.67 inch. The fuel assembly stresses resulting from this deflection indicated significant safety margins compared to the allowable values. The grid maximum impact force for both the seismic and lateral blowdown accident conditions occurred at the peripheral fuel assembly locations adjacent to the baffle wall. The grid impact forces were appreciably lower for fuel assembly locations inward from the peripheral fuel. For the lateral blowdown case, only a small (outer) portion of the core experienced significant grid impact forces.

The maximum grid impact force obtained from the limiting rupture break was found to be approximately 68 percent of the minimum grid strength (using the 95 x 95 value as determined by tests at reactor operating safe shutdown temperatures). The maximum square-root-of-the-sum-of-the-squares combination of the pipe rupture and safe shutdown earthquake loads for the limiting grid location was found to be approximately 74 percent of the minimum grid strength.

The major components that determine the structural integrity of the fuel assembly are the grids. Mechanical testing and analysis of the Vantage 5H Zircaloy grid and fuel assembly have demonstrated that the Vantage 5H structural integrity under seismic/LOCA loads will provide margins comparable to the STD 17 x 17 fuel assembly design and will meet all design bases.

Since the Vantage+ assembly is structurally similar to that of Vantage 5H, the seismic and LOCA analysis for the Vantage 5H assembly are applicable to Vantage+ assembly. The use of ZIRLO™ guide thimbles will not affect the seismic and LOCA loads.

A Salem plant specific seismic and LOCA analysis was performed for the RFA (Reference 22). The results of this analysis demonstrate that the RFA and V5H fuel assembly designs are capable of maintaining a coolable core geometry and control rod insertability under the combined seismic and LOCA loading for both a homogeneous and mixed core of fuel assembly designs.

4.2.1.3.3 Operational Experience

Westinghouse has had considerable experience with Zircaloy-clad fuel since its introduction in the Jose Cabrera plant in June 1968. This experience is extensively described in Reference 2.

For the LOCA plus the DBE condition, the deflection criteria of critical internal structures are the limiting values given in Table 4.2-1. The corresponding no loss of function limits are included in Table 4.2-1 for comparison purposes with the allowed criteria.

The criteria for the core drop accident are based upon analyses which have been performed to determine the total downward displacement of the internal structures following a hypothesized core drop resulting from loss of the normal core barrel supports. The initial clearance between the secondary core support structures and the reactor vessel lower head in the hot condition is approximately 1/2 inch. An additional displacement of approximately 3/4 inch would occur due to strain of the energy absorbing devices of the secondary core support; thus the total drop distance is about 1 1/4 inches which is insufficient to permit the grips of the rod cluster control assembly to come out of the guide thimble in the fuel assemblies.

Specifically, the secondary core support is a device which will never be used, except during a hypothetical accident of the core support (core barrel, barrel flange, etc.). There are four supports in each reactor. This device limits the fall of the core and absorbs the energy of the fall which otherwise would be imparted to the vessel. The energy of the fall is calculated assuming a complete and instantaneous failure of the primary core support and is absorbed during the plastic deformation of the controlled volume of stainless steel, loaded in tension. The maximum deformation of this austenitic stainless piece is limited to approximately 15 percent, after which a positive step is provided to ensure support.

4.2.2.5 Design Criteria Basis

The basis for the design stress and deflection criteria is identified below.

Allowable Stress

For normal operating conditions, Section III of the ASME Nuclear Power Plant Components Code is used as a basis for evaluating acceptability of calculated stresses. Both static and alternating stress intensities are considered. Under Code Case 1618, bolt material Type 316 stainless steel is now covered in ASME Section III and is so treated. It should be noted that the allowable stresses in Section III of the ASME Code are based on unirradiated material properties. In view of the fact that irradiation increases the strength of the Type 304 stainless steel used for the internals, although decreasing its elongation, it is considered that use of the allowable stresses in Section III is appropriate and conservative for irradiated internal structures.

The allowable stress limits during the DBA used for the core support structures are based on the January 1971 draft of the ASME Code for Core Support Structures, Subsection NG, and the Criteria for Faulted Conditions.

4.2.3 Reactivity Control System

4.2.3.1 Design Bases

Bases for temperature, stress on structural members, and material compatibility are imposed on the design of the reactivity control components.

4.2.3.1.1 Design Stresses

The Reactivity Control System is designed to withstand stresses originating from various operating conditions as summarized in Table 5.2-10.

Allowable Stresses: For normal operating conditions, Section III of the ASME Boiler and Pressure Code is used as a general guide.

Dynamic Analysis: The cyclic stresses due to dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the Reactivity Control System.

4.2.3.1.2 Material Compatibility

Materials are selected for compatibility in a PWR environment, for adequate mechanical properties at room and operating temperature, for resistance to adverse property changes in a radioactive environment, and for compatibility with interfacing components.

4.2.3.1.3 Reactivity Control Components

The reactivity control components are subdivided into two categories:

1. Permanent devices used to control or monitor the core

2. Temporary devices used to control or monitor the core.

The permanent type components are the rod cluster control assemblies, control rod drive assemblies, neutron source assemblies, and thimble plug assemblies. Although the thimble plug assembly does not directly contribute to the reactivity control of the reactor, it is presented as a Reactivity Control System component in this document because it can be used to restrict bypass flow through those thimbles not occupied by absorber, source, or burnable absorber rods.

The temporary component is the burnable absorber assembly. The design bases for each of the mentioned components are in the following paragraphs.

Absorber Rods

The following are considered design conditions under Subsections NG and NB of the ASME Boiler and Pressure Vessel Code Section III.

1. The external pressure equal to the Reactor Coolant System operating pressure

2. The wear allowance equivalent to 1,000 reactor trips

3. Bending of the rod due to a misalignment in the guide tube

4. Forces imposed on the rods during rod drop

5. Loads caused by accelerations imposed by the control rod drive mechanism

6. Radiation exposure for maximum core life

7. Temperature effects at operating conditions

The absorber material temperature shall not exceed its melting temperature (1470°F for Ag-In-Cd absorber material)(14).

Burnable Absorber Rods

Two kinds of discrete burnable absorber rods may be used at Salem. The first is the borosilicate glass (PYREX) burnable absorber. The second is the Wet Annular Burnable Absorber (WABA) design. See Reference 23 of this section for a more detailed discussion of WABA. Discrete burnable absorbers are utilized to meet nuclear design requirements of UFSAR Section 4.3. Some comparative data is also shown in UFSAR Table 4.3-1.

The burnable absorber rod clad is designed using Subsections NG and NB of the ASME Boiler and Pressure Vessel Code, Section III, 1973 as a general guide for Conditions I and II. For abnormal loads during Conditions III and IV, Code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must

not interfere with reactor shutdown or emergency cooling of the fuel rods.

The burnable absorber material is nonstructural. The structural elements of the burnable absorber rods are designed to maintain the absorber geometry even if the absorber material is fractured. The PYREX rods are designed so that the borosilicate absorber material is below its softening temperature (1492°F* for reference 12.5 weight percent boron rods). The WABA rods utilize an aluminum oxide/boron carbide (Al_2O_3-B_4C) absorber material which is a sintered ceramic and has a very high melting temperature. In addition, the structural elements are designed to prevent excessive slumping.

Neutron Source Rods

The neutron source rods are designed to withstand the following:

1. The external pressure equal to the Reactor Coolant System operating pressure

2. An internal pressure equal to the pressure generated by released gases over the source rod life

Thimble Plug Assembly

If used in the core (optional), the thimble plug assemblies satisfy the following:

1. Accommodate the differential thermal expansion between the fuel assembly and the core internals

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* Borosilicate glass is accepted for use in burnable absorber rods if the softening temperature is 1510 + 18°F. The softening temperature is defined in ASTM C 338.

2. Maintain positive contact with the fuel assembly and the core internals

3. Limit the flow through each occupied thimble to acceptable design value

4.2.3.1.4 Control Rod Drive Mechanisms

The mechanisms are Class I components designed to meet the stress requirements for normal operating conditions of Section III of the ASME Boiler and Pressure Vessel Code. Both static and alternating stress intensities are considered. The stresses originating from the required design transients are included in the analysis.

A dynamic seismic analysis is required on the control rod drive mechanism (CRDM) when a seismic disturbance has been postulated to confirm the ability of the mechanism to meet ASME Code, Section III allowable stresses and to confirm its ability to trip when subjected to the seismic disturbance.

The CRDM design used for the 17 x 17 fuel assembly control rod is identical to the 15 x 15 CRDM. The seismic analysis and response of 17 x 17 CRDM will be identical to those of the 15 x 15 mechanisms.

Control Rod Drive Mechanism Operational Requirements

The basic operational requirements for the CRDMs are as follows:

1. 5/8-inch step

2. 150-inch travel

3. 360-pound maximum load

4. Step in or out at 45 inches/minute (72 steps/minute)

Burnable Absorber Assembly

Each burnable absorber assembly consists of burnable absorber rods attached to a holddown assembly. Burnable absorber assemblies are shown on Figure 4.2-16.

The PYREX absorber rods consist of borosilicate glass tubes contained within Type 304 stainless steel tubular cladding which is plugged and seal welded at the ends to encapsulate the glass. The glass is also supported along the length of its inside diameter by a thin wall tubular inner liner of Type 304 stainless steel. The top end of the liner is open to permit the diffused helium to pass into the void volume and the liner overhangs the glass. The liner has an outward flange at the bottom end to maintain the position of the liner with the glass. A PYREX burnable absorber rod is shown in longitudinal and transverse cross sections on Figure 4.2-17.

The WABA consist of aluminum oxide/boron carbide pellets contained within Type 304 stainless steel tubular cladding which is plugged and seal welded at the ends to encapsulate the pellets. The pellets are also supported along the length of their insider diameter by a thin wall tubular liner of Type 304 stainless steel. The top and bottom of the inner tube, or liner, is open to allow for coolant flow. There is a void above the Al_2O_3-B_4C pellets between the inner and outer tube to contain diffused helium. A cross section drawing of the WABA rod is shown in Figure 4.2-17A.

The rods are statically suspended and positioned in selected guide thimbles within specified fuel assemblies. The absorber rods in each fuel assembly are grouped and attached together at the top end of the rods to a holddown assembly by a flat, perforated retaining plate which fits within the fuel assembly top nozzle and rests on the adaptor plate. The retaining plate (and the absorber rods) is held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. This arrangement assures that the absorber rods cannot be ejected from the core by flow forces. Each rod is permanently attached to the base plate by a nut which is lock welded into place.

The clad in the rod assemblies is slightly cold worked Type 304 stainless steel. All other structural materials are Type 304 or 308 stainless steel except for the springs which are Inconel 718. The borosilicate glass tube and /or aluminum oxide/boron carbide pellets provide sufficient boron content to meet the criteria discussed in Section 4.3.1.

Neutron Source Assembly

A neutron source assembly can be used to provide a base neutron level to monitor core multiplication to changes in core reactivity. Since there is very little neutron activity when the core is subcritical, such as refueling and approach to criticality, neutron source assemblies are placed in the reactor to provide a count rate greater than 1 cps in Mode 3 prior to starting the approach to critical on the source range monitors. The source range monitors, which receive their signal from the source range detectors, are used primarily when the core is subcritical and during special subcritical modes of operation. In addition to having a greater than 1 cps count rate, the source channels should maintain a signal to noise ratio of at least two in Mode 3 prior to beginning the approach to critical.

The source assembly also supplements detection of changes in the core multiplication factor during core loading, refueling and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Therefore a change in the multiplication factor can be detected during addition of fuel assemblies while loading the core, a change in control rod positions, and changes in boron concentration.

Both primary and secondary neutron source rods are used. The primary source rod, containing a radioactive material, spontaneously emits neutrons during the initial core loading and reactor startup. After the primary source rod decays beyond the desired neutron flux level, neutrons are then supplied by the secondary source rod. The secondary source rod contains a stable material which must be activated by neutron bombardment during reactor operation. The activation results in the subsequent release of neutrons. This becomes a source of neutrons during periods of low neutron flux, such as during refueling and subsequent startups.

The initial reactor core employs four source assemblies, two primary source assemblies, and two secondary source assemblies. Each primary source assembly contains one primary source rod and between 0 and 23 burnable absorber rods. Each secondary source assembly contains a symmetrical grouping of 4 or 6 secondary source rods and between 0 and 20 burnable absorber rods. The 4 rodlet secondary source utilizes a single encapsulated design. The 6 rodlet secondary source utilizes a double encapsulated design which provides additional margin against source material leakage. Locations not filled with a source or burnable absorber rod may contain a thimble plug (optional). Source assemblies are shown on Figures 4.2-18 and 4.2-19. A comparison of the single and double encapsulated secondary source design is provided in Table 4.2-2.

Following the initial operating cycle, the actual source range count rate will depend on the core loading and the outage duration. Normally for subsequent reloads, the primary sources are removed and the secondary sources continue functioning.

The core loading determines the placement of the secondary sources and other inherent neutron sources (i.e., spontaneous fission from the irradiated fuel) relative to the location of the source range detectors. For secondary source assemblies made of antimony-beryllium (Sb-Be, gamma-neutron reaction), ^{124}Sb has a 60.2 day half-life. Thus, extended outages may impact the effectiveness of the secondary sources. For such extended outages, inherent neutron sources are sufficient to provide the required greater than 1 cps count rate in Mode 3 prior to beginning the approach to critical.

The primary and secondary source rods both utilize the same cladding material as the absorber rods. The single encapsulated secondary source rods contain approximately 500 grams of Sb-Be pellets in one rod. The double encapsulated secondary source rods contain approximately 338 grams of Sb-Be pellets in one rod. The primary source rods contain capsules of Californium source material and alumina spacer rods to position the source material within the cladding. The rods in each assembly are permanently fastened at the top end to a holddown assembly, which is identical to that of the burnable absorber assemblies.

The other structural members are constructed of Type 304 stainless steel except for the springs. The springs exposed to the reactor coolant are wound from an age hardened nickel base alloy for corrosion resistance and high strength. The springs, when contained within the rods where corrosion resistance is not necessary, are oil tempered carbon steel.

Thimble Plug Assembly

Thimble plug assemblies may be used in order to limit bypass flow through the rod cluster control guide thimbles in fuel assemblies which do not contain either control rods, source rods, or burnable absorber rods.

The thimble plug assemblies as shown on Figure 4.2-20 consist of a flat base plate with short rods suspended from the bottom surface and a spring pack assembly. The 24 short rods, called thimble plugs, project into the upper ends of the guide thimbles to reduce the bypass flow area. Similar short rods are also used on the

source assemblies and burnable absorber assemblies to plug the ends of all vacant fuel assembly guide thimbles. At installation in the core, the thimble plug assemblies interface with both the upper core plate and with the fuel assembly top nozzles by resting on the adaptor plate. The spring pack is compressed by the upper core plate when the upper internals assembly is lowered into place. Each thimble plug is permanently attached to the base plate by a nut which is locked to the threaded end of the plug by a small lock-bar welded to the nut.

All components in the thimble plug assembly, except for the springs, are constructed from Type 304 stainless steel. The springs are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.2.2 Control Rod Drive Mechanism

All parts exposed to reactor coolant are made of metals which resist the corrosive action of the water. Three types of metals are used exclusively: stainless steels, Inconel-X and cobalt based alloys. Wherever magnetic flux is carried by parts exposed to the main coolant, 400 series stainless steel is used. Cobalt based alloys are used for the pins and latch tips. Inconel-X is used for the springs of both latch assemblies and Type 304 stainless steel is used for all pressure containing parts. Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts.

A position indicator assembly slides over the CRDM rod travel housing. It detects the drive rod assembly position by means of 42 discrete coils that magnetically sense the entry and presence of the rod drive line through its center line over the normal length of the drive rod travel.

(e.g., Cl^- control in the coolant). The current design type reactivity controls have been in service for more than 10 years with no apparent degradation of construction materials.

With regard to the materials of construction exhibiting satisfactory resistance to adverse property changes in a radioactive environment, it should be noted that on work on breeder reactors in current design, similar materials are being applied. At high fluences the austenitic materials increase in strength with a corresponding decreased ductility (as measured by tensile tests) but energy absorption (as measured by impact tests) remains quite high. Corrosion of the materials exposed to the coolant is quite low and proper control of Cl^- and O_2 in the coolant will prevent the occurrence of stress corrosion. All of the austenitic stainless steel base materials used are processed and fabricated to preclude sensitization.

Analysis of the rod cluster control assemblies shows that if the drive mechanism housing ruptures, the rod cluster control assembly will be ejected from the core by the pressure differential of the operating pressure and ambient pressure across the drive rod assembly. The ejection is also predicted on the failure of the drive mechanism to retain the drive rod/rod cluster control assembly position. It should be pointed out that a drive mechanism housing rupture will cause the ejection of only one rod cluster control assembly with the other assemblies remaining in the core.

Ejection of a burnable absorber or thimble plug assembly (if used) is conceivable based on the postulation that the holddown bar fails and that the base plate and burnable absorber rods are severely deformed. In the unlikely event that failure of the holddown bar occurs, the upward displacement of the burnable absorber assembly only permits the base plate to contact the upper core plate. Since this displacement is small, the major portion of the burnable absorber material remains positioned within the core. In the case of the thimble plug assembly, the thimble plugs will partially remain in the fuel assembly guide thimbles thus maintaining a majority of the desired flow impedance. Further displacement or complete ejection would necessitate the square base plate and burnable absorber rods be forced, thus plastically deformed, to fit up through a smaller diameter hole. It is expected that this condition requires a substantially higher force or pressure drop than that of the holddown bar failure.

Experience with control rods, burnable absorber rods, and source rods is discussed in Reference 2.

The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts. The results of the review are summarized below.

Rod Cluster Control Assembly

1. The basic absorbing material is sealed from contact with the primary coolant and the fuel assembly and guidance surfaces by a high quality stainless steel clad.

14. Cohen, J., "Development and Properties of Silver Base Alloys as Control Rod Materials for Pressurized Water Reactors," WAPD-214, December 1959.

15. Davidson, S. L. (Ed.), et al, "Vantage 5 Fuel Assembly Reference Core Report," WCAP-10444-P-A, September 1985.

16. Davidson, S. L. (Ed.), et al, "Vantage 5H Fuel Assembly," WCAP-10444-P-A, Addendum 2-A, February 1989.

17. Weiner, R. A., "Improved Fuel Rod Performance Models for Westinghouse Fuel Rod Design and Safety Evaluation," WCAP-10851-P-A, August 1988.

18. Letter from A. C. Thadani, (NRC) to S. R. Tritch (Westinghouse), "Acceptance for Referencing of Topical Report WCAP-12610 'Vantage+ Fuel Assembly Reference Core Report'," July 1, 1991.

19. Letter from W. J. Rinkacs (Westinghouse) to M. M. Mannion (PSE&G), "Westinghouse Fuel Features Recommendation for Cycle 11", July 22, 1998

20. Letter from W. J. Rinkacs (Westinghouse) to T. K. Ross (PSE&G), "Design Reviews for Fuel Feature Changes Proposed for Cycle 11", July 22, 1998

21. Letter from W. J. Rinkacs (Westinghouse) to M. M. Mannion (PSE&G), "Westinghouse Generic Safety Evaluation for the 17x17 Standard Robust Fuel Assembly", October 1, 1998

22. Letter from B. W. Gergos (Westinghouse) to T. K. Ross (PSE&G), "Seismic/ LOCA Analysis of the Robust Fuel Assemblies", February 4, 1999

23. Iorii, J. A. and Petrarca, D. J., "Westinghouse Wet Annular Burnable Absorber Evaluation Report", WCAP-10021-P-A, Revision 1, October 1983

Discussion

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping and no operator action or control action is required to suppress them. The stability of diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual control rods. Such oscillations are readily observable and alarmed, using the ex-core long ion chambers. Indications are also continuously available from in-core thermocouples and loop temperature measurements. Moveable in-core detectors can be activated to provide more detailed information. In all presently proposed cores these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects designed into the core.

However, axial xenon spatial power oscillations may occur late in core life. The control bank and ex-core detectors are provided for control and monitoring of axial power distributions. Assurance that fuel design limits are not exceeded is provided by reactor overpower ΔT and overtemperature ΔT trip functions which use the measured axial power imbalance as an input.

4.3.1.7 Anticipated Transients Without Trip

The effects of anticipated transients with failure to trip are not considered in the design bases of the plant. Analysis has shown that the likelihood of such a hypothetical event is negligibly small. Furthermore, analysis of the consequences of a hypothetical failure to trip following anticipated transients has shown that no significant core damage would result and system peak pressures would be limited to acceptable values and no failure of the RCS would result (1).

4.3.2 Description

4.3.2.1 Nuclear Design Description

The reactor cores consist of a specified number of fuel rods which are held in bundles by spacer grids and top and bottom fittings. The fuel rods are constructed of Zircaloy or Zirlo™ cylindrical tubes containing UO_2 fuel pellets. The bundles, known as fuel assemblies, are arranged in a pattern which approximates a right circular cylinder.

Each fuel assembly contains a 17 x 17 rod array composed of 264 fuel rods, 24 rod cluster control (RCC) thimbles and an in-core instrumentation thimble. Figure 4.2-1 shows a cross sectional view of a 17 x 17 fuel assembly and the related RCC locations. Further details of the fuel assembly are given in Section 4.2.1.

For initial core loading, the fuel rods within a given assembly have the same uranium enrichment in both the radial and axial planes. Fuel assemblies of three different enrichments are used in the initial core loadings to establish a favorable radial power distribution. Two regions consisting of two lower enrichments are interspersed so as to form a checkerboard pattern in the central portion of the core. The third region is arranged around the periphery of the core and contains the highest enrichment. The enrichments for the first cores are shown in Table 4.3-1.

A typical reload pattern is a low leakage loading pattern or a low-low leakage pattern. A low leakage loading pattern has either burned (depleted) or fresh (feed) assemblies arranged on the core periphery. A low-low leakage pattern has only burned (depleted) assemblies arranged on the core periphery. The reload cores are normally designed to be able to operate approximately eighteen months between refuelings. The current cycles' loading patterns for both Salem Units are shown in Section 4.5.

The core average enrichment is determined by the amount of fissionable material required to provide the desired cycle energy requirements. The physics of the burnout process is such that operation of the reactor depletes the amount of fuel available due to the absorption of neutrons by the U-235 atoms and their subsequent fission. The rate of U-235 depletion is directly proportional to the power level at which the reactor is operated. In addition, the fission process results in the formation of fisson products, some of which readily absorb neutrons. These effects, depletion and the buildup of fission products, are partially offset by the buildup of plutonium shown on Figure 4.3-1 for the 17 x 17 fuel assembly, which occurs due to the non-fission absorption of neutrons in U-238. Therefore, at the beginning of any cycle a reactivity reserve equal to the depletion of the fissionable fuel and the buildup of fission product poisons over the specified cycle life must be "built" into the reactor. This excess reactivity is controlled by boron dissolved in the primary coolant and burnable absorbers.

The concentration of boric acid in the primary coolant is varied to provide control and to compensate for long-term reactivity requirements. The concentration of the soluble neutron absorber is varied to compensate for reactivity changes due to fuel burnup, fission product poisoning including xenon and samarium, burnable absorber depletion, and the cold-to-operating moderator temperature change. Using its normal makeup path, the Chemical and Volume Control System (CVCS) is capable of inserting negative reactivity at a rate of approximately 30 pcm/min when the reactor coolant boron concentration is 1000 ppm and approximately 35 pcm/min when the reactor coolant boron concentration is 100 ppm. The peak burnout rate for xenon is 25 pcm/min. Rapid transient reactivity requirements and safety shutdown requirements are met with control rods.

As the boron concentration is increased, the moderator temperature coefficient becomes less negative. The use of a soluable absorber alone would result in a positive moderator coefficient at beginning-of-life (BOL). Therefore, burnable absorbers are used to reduce the soluble boron concentration sufficiently to ensure that the moderator temperature coefficient is non-positive for power operating conditions. During operation the absorber content in the burnable absorbers is depleted thus adding positive reactivity to offset some of the negative reactivity from fuel depletion and fission product buildup. The

depletion rate of the burnable absorbers is not critical since chemical shim is always available and flexible enough to cover any possible deviations in the expected burnable absorber depletion rate. Figure 4.3-2 is a graph of a typical core depletion with burnable absorbers.

As stated previously, the purpose of burnable absorbers (integral and discrete) is to provide enough boron loading in the core to decrease core soluble boron concentrations to the point that a negative moderator temperature coefficient is maintained at all hot operating conditions. IFBA boron loadings in the range from 1.57 to 2.35 mg/inch per rod is typical. Two different discrete burnable absorbers (borosilicate glass-PYREX) and Wet Annular Burnable Absorbers (WABA) may be used. Both discrete absorbers have similar burnout characteristics and provide similar benefits to core design development which include reduction of the number and loading of the IFBA, which is a fuel performance (rod internal pressure, corrosion, and DNB propagation) benefit. Typical stack lengths for IFBA and WABA range from 108 to 132 inches. PYREX rods are 139 inches in length. Design data for IFBA, WABA, an PYREX can be seen in Table 4.3-1. Reference 32 of this section provides a more detailed discussion of WABA.

In addition to reactivity control, the burnable absorbers, both discrete (WABA and/or PYREX) and integral (IFBA), are strategically located to provide a favorable radial power distribution. Reload loading patterns utilize various burnable absorber types and distributions. These are determined on a cycle-specific basis. The current cycles' burnable absorber loading patterns are shown in Section 4.5.

Tables 4.3-1 through 4.3-3 contain a summary of the reactor core design parameters for a typical fuel cycle, including reactivity coefficients, delayed neutron fraction, and neutron lifetimes. Some of these parameters change on a reload basis. The current values or allowable range of values may be found in the appropriate Reload Safety Evaluation (RSE) or Nuclear Design Report (NDR). A list of applicable RSEs and NDRs, by unit and cycle, is given in Section 4.5. The RSE is a cycle-specific document which evaluates the fuel assembly design and core loading pattern configuration for plant safety. The NDR is a cycle-specific document which includes such information as power distributions, reactivity coefficients, boron and control rod worths under a variety of plant operating conditions. There is sufficient information in the RSE and NDR to permit an independent calculation of the nuclear performance characteristics of the core.

5. Fuel cycle lifetimes

6. Rod bank worths

7. Rod bank overlaps

8. Burnable absorber length and placement

Normal operation of the plant assumes compliance with the following conditions:

1. Control rods in a single bank move together with no individual rod insertion differing by more than 12 steps above 85% RTP or more than 18 steps at or below 85% RTP from the bank demand position.

2. Control banks are sequenced with overlapping banks.

3. The control bank insertion limits are not violated.

4. Axial power distribution procedures, which are given in terms of flux difference control and control bank position, are observed.

The axial power distribution procedures referred to above are part of the required operating procedures which are followed in normal operation. They require control of the axial offset (flux difference divided by fractional power) at all power levels within a permissible operating band of a target value corresponding to the equilibrium full power value. In the first cycle, the target value changes from about -10 percent to 0 percent linearly through the life of the cycle. Target values in a reload cycle vary based on previous cycle length and number of fresh assemblies. These cycle-specific target values are available in the appropriate NDR. Section 4.5 contains a list. This minimizes xenon transient effects on the axial power distribution since the procedures essentially keep the xenon distribution in phase with the power distribution.

Calculations are performed for normal operation of the reactor including load following maneuvers. Beginning, middle, and end-of-cycle conditions are included in the calculations. Different histories of operation are assumed prior to calculating the effect of load follow transients on the axial power

distribution. These different histories assume base loaded operation and extensive load following. The calculated points have been synthesized from axial calculations combined with radial factors appropriate for rodded and unrodded planes. The calculated values have been increased by a factor of 1.05 for conservatism and a factor of 1.03 for the engineering factor, F.

Figure 4.3-11 represents these results as an upper bound envelope on local power density versus elevation in the core. It should be emphasized that this envelope is a conservative representation of the bounding values of local power density. Expected values are considerably smaller and, in fact, less conservative bounding values may be justified with additional analysis or surveillance requirements.

Finally, as previously discussed, this upper bound envelope is based on procedures of load follow which require the operator to operate within an allowed deviation from a target equilibrium value of axial flux difference, observing certain D bank insertion limits. These procedures are detailed in Technical Specifications and are predicated only upon ex-core surveillance supplemented by the normal monthly full core map requirement and by computer based alarms on deviation and time of deviation from the allowed flux difference band.

Allowing for fuel densification effects, the average kW/ft for both Units 1 and 2 is 5.44. From Figure 4.3-11, the conservative upper bound value of normalized local power density, including allowances for densification effects, is 2.40 corresponding to a peak local power density of 13.3 kW/ft at 102 percent power for Units 1 and 2.

To determine Reactor Protection System setpoints, with respect to power distributions, three categories of events are considered, namely rod control equipment malfunctions, operator errors of commission, and operator errors of omission.

The first category comprises uncontrolled rod withdrawal (with rods moving in the normal bank sequence) for full length rod banks. Also included are motions of the full length rod banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions were calculated throughout these occurrences assuming short-term corrective action, that is no transient xenon effects were considered to result from the malfunction. The event was assumed to occur from typical normal operating situations which did include normal xenon transients. It was further assumed in determining the power distributions that total power level would be limited by reactor trip to below 118 percent. Since the study is to determine protection limits with respect to power and axial offset, no credit was taken for trip setpoint reduction due to flux difference. Results are given on Figure 4.3-12 in units of kW/ft. The peak power density which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for centerline melt including uncertainties and densification effects. The second category, also appearing in Figure 4.3-12, assumes that the operator mis-positions the full length rod bank in violation of the insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a flux difference violation. Representative results shown on Figure 4.3-13 are F_Q multiplied by 102 percent power including an allowance for calorimetric error. The figure shows that provided the assumed error in operation does not continue for a period which is long compared to the xenon time constant, the maximum

local power does not exceed 22.4 kW/ft including the above factors. However, the COLR restrict ΔI at 102 percent power such that the peak linear power density is less than 18 kW/ft. These events are considered Condition II events.

It should be noted that a reactor overpower accident is not assumed to occur coincident with an independent operator error.

Analyses of possible operating power shapes show that the appropriate hot channel factors F_Q and $F^N_{\Delta H}$ for peak local power density and for DNB analysis at full power are the values given in the COLR. The current unit and cycle's COLR reference is given in Section 4.5. Typical values are given in Table 4.3-2.

F_Q can be increased with decreasing power as shown in the Technical Specifications. Increasing $F^N_{\Delta H}$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits as described in Section 4.4.3.2. It has been determined that provided the above Conditions I through IV are observed, the Technical Specification limits are met.

When a situation is possible in normal operation which could result in local power densities in excess of those assumed as the pre-condition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided for returning the core to a safe condition. These alarms are described in detail in Sections 7 and 16.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject is discussed in depth in Reference 2. A summary of this report is given here.

In a measurement of peak local power density, F_Q, with the moveable detector system described in Section 7.6, the following uncertainties have to be considered:

1. Reproducibility of the measured signal

2. Errors in the calculated relationship between detector current and local flux

3. Errors in the calculated relationship between detector flux and peak rod power some distance from the measurement thimble.

The appropriate allowance for 1 above has been quantified by repetitive measurements made with several inter-calibrated detectors by using the common thimble features of the In-core Detector System. This system allows more than one detector to access any thimble. Errors in category 2 above are quantified to the extent possible, by using the fluxes measured at one thimble location to predict fluxes at another location which is also measured. Local power distribution predictions are verified in critical experiments on arrays of rods with simulated guide thimbles, control rods, burnable poisons, etc. These critical experiments provide quantification of error of types 2 and 3 above.

Reference 2 describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurements taken on two Westinghouse plants with In-core Detector Systems of the same type as used in the plant described herein. The report concludes that the uncertainty associated with the peak nuclear heat flux factor, F_Q, is 4.58 percent at the 95 percent confidence level with only 5 percent of the measurements greater than the inferred value. This is the equivalent of a 2σ limit on a normal distribution and is the uncertainty to be associated with a full core flux map with moveable detectors reduced with a reasonable set of input data incorporating the influence of burnup on the radial power distribution. The uncertainty is usually rounded up to 5 percent.

In comparing measured power distributions (or detector currents) against the calculations for the same situation, it is not possible to subtract out the detector reproducibility. Thus a comparison between measured and predicted power distributions has to include some measurement error. Such a comparison is given on Figure 4.3-14 for one of the maps used in Reference 2. Since the first publication of the report, hundreds of maps have been taken on these and other reactors. The results confirm the adequacy of the 5 percent uncertainty allowance on the calculated F_Q.

A similar analysis for the uncertainty in $F_{\Delta H}$ (rod integral power) measurements results in an allowance of 3.60 percent at the equivalent of a 2σ confidence level. For historical reasons, an 8 percent uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integrals at full power must not exceed the design $F_{\Delta H}$ less 8 percent. This 8 percent may be reduced in final design to 4 percent to allow a wider range of acceptable axial power distributions in the DNB analysis and still meet the design bases of Section 4.3.1.3.

A measurement in the second cycle of a 121 assembly, 12 foot core is compared with a simplified one dimensional core average axial calculation on Figure 4.3-15. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation is basically of three types:

1. Much of the data is obtained in steady state operation at constant power in the normal operating configuration.

2. Data with unusual values of axial offset have been obtained in the past as part of the multi-point ex-core detector calibration exercise which is performed monthly.

3. Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in Reference 6. Figure 4.3-16 contains a summary of measured values of F_Q as a function of axial offset for five plants from that report.

4.3.2.2.8 Testing

A very extensive series of physics tests is performed on first cores. These tests are described in Section 14. Since not all limiting situations can be created at BOL, the main purpose of the tests is to provide a check on the calculational methods used in the predictions for the conditions of the test. Low power physics tests are performed at the beginning of each reload cycle to confirm the validity of the cycle-specific design models that are used in the calculations supporting the Reload Safety Evaluation. The physics tests measure the critical boron concentration, isothermal temperature coefficient and control rod worth and compare the results to predictions calculated by the design models. Additionally, moveable in-core detectors are used to measure nuclear and safety related parameters during the initial power ascension and periodically throughout the cycle operation. The measurements are used to ensure that the measured parameters are within the limiting values contained in the Technical Specifications, as well as to compare the corresponding parameters to the design models for validation.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration and errors are described in References 2, 5, and 6. The relevant conclusions are summarized here in Section 4.3.2.2.7.

Provided the limitations given in Section 4.3.2.2.6 on rod insertion and flux difference are observed, the Ex-core Detector System provides adequate monitoring of power distributions.

Further details of specific limits on the observed rod positions and flux difference are given in the COLR (See Section 4.5).

Limits for alarms, reactor trip, etc. are given in the Technical Specifications. Descriptions of the systems provided are given in Section 7.7.

4.3.2.3 Reactivity Coefficients

The kinetic characteristics of the reactor core determine the response of the core to changing plant conditions or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect the changes in the neutron multiplication due to varying plant conditions such as power, moderator, or fuel temperatures, or less significantly due to a change in pressure or void conditions. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant throughout life. The results of such simulations and the reactivity coefficients used are presented in Section 15. The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 4.3.3. These models have been confirmed through extensive testing of more than thirty cores similar to the plant described herein; results of these tests are discussed in Section 4.3.3. Quantitative information for calculated reactivity coefficients, including fuel Doppler coefficient, moderator coefficients (density, temperature, pressure, void) and power coefficient is given in the following sections.

4.3.2.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes such as U-236, Np-237 etc. are also considered but their contributions to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the requirements specified in Table 4.3-3. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability requirements are met. Analyses indicate that the first requirement can be met either by a single group or by two or more banks whose total worth equals at least the required amount. The axial power shape would be more peaked following movement of a single group of rods worth 3 to 4 percent $\Delta\rho$; therefore, four banks (described as A, B, C, and D on Figures 4.3-26A and B) each worth approximately 1 percent $\Delta\rho$ have been selected.

The position of control banks for criticality under any reactor condition is determined by the concentration of boron in the coolant. On an approach to criticality, boron is adjusted to ensure that criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations (See the Technical Specifications).

Early in the cycle there may also be a withdrawal limit at low power to maintain a negative moderator temperature coefficient. Usual practice is to adjust boron to ensure that the rod position lies within the so-called maneuvering band, that is such that an escalation from zero power to full power does not require further adjustment of boron concentration.

Ejected rod worths are given in Section 15.3.1.6 for several different conditions. Experimental confirmation of these worths can be found by reference to startup test reports (9).

Allowable deviations due to misaligned control rods are discussed in the Technical Specifications.

A representative calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) is given on Figure 4.3-27.

Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. The rod position versus time of travel after rod release assumed is given on Figure 4.3-28 for Vantage+ fuel. The drop time to the dashpot increases from 2.2 to 2.7 seconds for Vantage 5H, Vantage+, and RFA, with the other times increasing proportionately. For nuclear design purposes, the reactivity worth versus rod position is calculated by a series of steady state calculations at various control rod positions assuming all rods out of the core as the initial position in order to minimize the initial reactivity insertion rate. Also, to be conservative, the rod of highest worth is assumed stuck out of the core and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. The result of these calculations is shown on Figure 4.3-29.

The shutdown groups provide additional negative reactivity to assure an adequate shutdown margin. Shutdown margin is defined as the amount by which the core would be subcritical at hot shutdown if all RCCAs are tripped, but assuming that the highest worth assembly remains fully withdrawn and no changes in xenon or boron take place. The loss of control rod worth due to the material irradiation is negligible since only D bank rods may be in the core under normal operating conditions.

The values given in Table 4.3-3 show that the available reactivity in withdrawn RCCAs provides the design basis minimum shutdown margin allowing for the highest worth cluster to be at its fully withdrawn position. An allowance for uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.7 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside of the reactor is precluded by adequate design of fuel transfer and fuel storage facilities and by administrative control procedures. This section identifies those criteria important to criticality safety analyses.

New fuel is generally stored in fuel storage facilities with no water present but which are designed so as to prevent accidental criticality even if unborated water is present.

In the analysis for the storage facilities, the fuel assemblies are assumed to be in their most reactive condition, namely fresh or undepleted and with no control rods or removable neutron absorbers present. Assemblies cannot be closer together than the design separation provided by the storage facility except in special cases such as in fuel shipping containers where analyses are carried out to establish the acceptability of the design. The mechanical integrity of the fuel assembly is assumed and no credit is taken for neutron absorption properties of the storage facility unless specifically included in the design. For full flooding with unborated water, the fuel assembly spacing of the facility provides essentially full nuclear isolation, and k_{eff} for the array is no greater than k_{eff} for the single most reactive fuel assembly. The criterion for full flooding is $k_{eff} \leq 0.95$. For the analysis of new (dry) fuel storage racks, an additional criterion of $k_{eff} \leq 0.98$ is confirmed for optimum (low density) moderation conditions. These fresh fuel rack critically analyses[32] include appropriate allowances for uncertainties, biases, and manufacturing tolerances and assure 95 percent probability / 95 percent confidence level that the k_{eff} critically design criteria are met.

The fuel assembly (17 x 17 fuel rods) of standard design and 3.5 w/o enriched uranium oxide, without a control rod or burnable absorbers, fully flooded and reflected with cold clean water, has a k_{eff} of about 0.85. Two such fuel assemblies spaced 1 inch apart with parallel axes 9.5 inches apart have a k_{eff} of about 0.99. Three such fuel assemblies spaced 1 inch apart with parallel axes would be supercritical.

An infinite number of dry fuel assemblies of this design would have a k_{eff} < 0.80.

4.3.2.8 Stability

4.3.2.8.1 Introduction

The stability of the PWR cores against xenon-induced spatial oscillations and the control of such transients are discussed extensively (References 5, 10, 11, 12). A summary of these reports is given in the following discussion and the design bases are given in Section 4.3.1.6.

In a large reactor core, xenon-induced oscillations can take place with no corresponding change in the total power of the core. The oscillation may be caused by a power shift in the core which occurs rapidly by comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion and results in a change in the moderator density and fuel temperature distributions. Such a power shift could occur in the diametral plane of the core as a result of abnormal control action.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. Protection against total power stabilities is provided by the Control and Protection System as described in Chapter 7. Hence, the discussion on the core stability will be limited here to xenon-induced spatial oscillations.

4.3.2.8.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing the total core power. The overtones in the current PWRs, and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalues of the first flux overtones. Writing, either in the axial direction or in the X-Y plane, the eigenvalue, ε, of the first flux harmonic as

Then, a standard S4 discrete ordinates calculation solves for the angular distribution, based on the group-collapsed and homogenized cross-sections from the first step. These S4 fluxes normalize the detailed spatial and energy nodal fluxes, which are then used to compute reaction rates, power distributions and to deplete the fuel and burnable absorbers. A standard B1 calculation evaluates the fundamental mode critical spectrum, providing an improved fast difusion coefficient for the core spatial codes.

PHOENIX-P employs a multiple energy group library consisting of 42 or more energy groups derived mainly from ENDF/B files. This library was designed to capture the integral properties of the multigroup data properly during group collapse and to model important resonance parameters properly. It contains all neutronics data necessary for modeling fuel, fission products, cladding and structural materials, coolant, and control and burnable absorber materials present in the PWRs.

Group constants for burnable absorber cells, control rod cells, guide thimbles and instrumentation thimbles, or other non-fuel cells, can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or ID lattice codes.

4.3.3.3 Spatial Few-Group Diffusion Calculations

Historically, spatial few-group diffusion calculations consisted primarily of two-group X-Y calculations using an updated version of the TURTLE code and two-group axial calculations using an updated version of the PANDA code.

Discrete X-Y calculations (1 mesh per cell) were carried out to determine critical boron concentrations and power distributions in the X-Y plane. An axial average in the X-Y plane was obtained by synthesis from unrodded and rodded planes. Axial effects in unrodded depletion calculations were accounted for by the axial buckling, which varies with burnup and is determined by radial depletion calculations which are matched in reactivity to the analogous R-Z depletion calculation. The moderator coefficient is evaluated by varying the inlet temperature in the same X-Y calculations used for power distribution and reactivity predictions.

Validation of the reactivity calculations is associated with the validation of the group constants themselves, as discussed in Section 4.3.3.2. Validation of the Doppler calculations is associated with the fuel temperature validation discussed in Section 4.3.3.1. Validation of the moderator coefficient calculations is obtained by comparison with plant measurements at hot zero power conditions as shown in Table 4.3-11.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions (flyspeck curve). Group constants are obtained from the three-dimensional nodal model by flux-volume weighting on an axial slice-wise basis. Radial bucklings are determined by varying parameters in the buckling model while forcing the one-dimensional model to reproduce the axial characteristics (axial offset, mid-plane power) of the three-dimensional model.

Recent few-group spatial calculations have input PHOENIX-P supplied two-group cross-sections to the Advanced Nodal Code (ANC). ANC is a two-group, two or three-dimensional nodal code capable of determining typical nuclear design analyses, such as critical boron concentrations, average assembly and pin powers, control rod worths, reactivity coefficients, assembly and pin burnups and axial power distributions. Through the use of advanced nodal techniques, ANC is able to produce solutions similar to the fine mesh, finite difference diffusion theory codes such as TURTLE/TORTISE. ANC has been benchmarked against TORTISE (an improved version of TURTLE) for normal and off-normal conditions, such as ejected rod, stuck rod and dropped rod (Reference 31). The qualification of the PHOENIX-P/ANC methodology against measured data is given in Reference 30.

Validation of the spatial codes for calculating power distributions involves the use of in-core and ex-core detectors and is discussed in Section 4.3.2.2.7.

Based on comparison with measured data it is estimated that the accuracy of current analytical methods is:

- ± 0.2 percent $\Delta\rho$ for Doppler defect
- ± 2×10^{-5}/°F for moderator coefficient
- ± 50 ppm for critical boron concentration with depletion
- ± 3 percent for power distributions
- ± 0.2 percent $\Delta\rho$ for rod bank worth
- ± 4 pcm/step for differential rod worth
- ± 0.5 pcm/ppm for boron worth
- ± 0.1 percent $\Delta\rho$ for moderator defect

4.3.4 References for Section 4.3

1. "Westinghouse Anticipated Transients Without Reactor Trip Analysis," WCAP-8330, August 1974.

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33. Bradfute, J. L., et al, "Criticality Analysis of the Salem Units 1 and 2 Fresh Fuel racks", NFU-VTDWW-94-083-00, January 1994

4.4 THERMAL AND HYDRAULIC DESIGN

4.4.1 Design Basis

The overall objective of the thermal and hydraulic design of the reactor core is to provide adequate heat transfer which is compatible with the heat generation distribution in the core such that heat removal by the Reactor Coolant System (RCS) or the Emergency Core Cooling System (ECCS) (when applicable) assures that the following performance and safety criteria requirements are met:

1. Fuel damage* is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These will be within the capability of the Plant Cleanup System and are consistent with the plant design bases.

2. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged* although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

3. The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

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* Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod clad).

In order to satisfy the above criteria, the following design bases have been established for the thermal and hydraulic design of the reactor core.

4.4.1.1 Departure From Nucleate Boiling Design Basis

Basis

Departure from nucleate boiling (DNB) will not occur on at least 95 percent of the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition I and II events) at a 95 percent confidence level.

Discussion

The design method employed to meet the DNB design basis for the Vantage 5H, Vantage+, and RFA fuel assemblies is the Revised Thermal Design Procedure (RTDP), Reference 96. With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined such that there is at least a 95 percent probability at a 95 percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and operational transients, and during transient conditions arising from faults of moderate frequency (Condition I and II events as defined in ANSI N18.2).

Uncertainties in the plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and reactor coolant system flow) have been evaluated at Salem Units 1 and 2, Reference 114. Only the random portion of the plant operating parameters uncertainties is included in the statistical combination. Instrument bias is treated as a direct DNBR penalty. Since the parameter uncertainties are considered in determining the RTDP design limit DNBR values, the plant safety analyses are performed using input parameters at their nominal values.

The RTDP design limit DNBR values are 1.24 for both typical and thimble cells of the Vantage 5H and Vantage+ fuels and 1.25 and 1.23 for the typical and thimble cells, respectively for RFA fuel.

The design limit DNBR values are used as a basis for the technical specifications and for consideration of the applicability of unreviewed safety questions as defined in 10 CFR 50.59.

To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow (see paragraph 4.4.2.3.5) and transition cores (see paragraph 4.4.2.3.6), safety analyses were performed to DNBR limits higher than the design limit DNBR values. The difference between the design limit DNBRs and the safety analysis limit DNBRs results in available DNBR margin. The net DNBR margin, after consideration of all penalties, is available for operating and design flexibility.

The option of thimble plug removal has been included in all of the DNBR analyses performed for the Vantage 5H, Vantage+, and RFA fuel. The primary impact of thimble plug removal on the thermal hydraulic analysis is an increase in core bypass flow. Bypass flow is assumed to be ineffective for core heat removal. The increased bypass flow is included in all of the flow and DNBR values presented in Table 4.4-1.

Operation with thimble plugs in place reduces the core bypass flow through the fuel assembly thimble tubes. The reduction in core bypass flow for operation with the thimble plugs in place is a DNBR benefit. The increased margin associated with the use of a full compliment of thimble plugs can be used to offset DNBR penalties.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. In the STDP methodology, the parameters used in the analysis are treated in a conservative way from a DNBR standpoint. The parameter uncertainties are applied directly to the plant safety analyses input values to give the lowest minimum DNBR. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

By preventing DNB, adequate heat transfer is assured between the fuel clad and the reactor coolant, thereby preventing clad damage as a result of inadequate cooling. Maximum fuel rod surface temperature is not a design basis as it will be within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis will be met for transients associated with Condition II events including overpower transients. There is an additional large DNBR margin at rated power operation and during normal operating transients.

4.4.1.2 Fuel Temperature Design Basis

Basis

During modes of operation associated with Condition I and Condition II events, the maximum fuel temperature shall be less than the melting temperature of uranium dioxide (UO_2). The UO_2

melting temperature for at least 95 percent of the peak kW/ft fuel rods will not be exceeded at the 95 percent confidence level. The melting temperature of UO_2 is taken as 5080°F (1) unirradiated and decreasing 58°F per 10,000 MWD/MTU. By precluding UO_2 melting, the fuel geometry is preserved and possible adverse effects of molten UO_2 on the cladding are eliminated. To preclude center melting and as a basis for overpower protection system setpoints, a calculated centerline fuel temperature of 4700°F has been selected as the overpower limit. This provides sufficient margin for uncertainties in the thermal evaluations as described in Section 4.4.2.10.1.

Discussion

Fuel rod thermal evaluations are performed at rated power, maximum overpower and during transients at various burnups. These analyses assure that this design basis, as well as the fuel integrity design bases given in Section 4.2, are met. They also provide input for the evaluation of Condition III and IV faults given in Section 15.

4.4.1.3 Core Flow Design Basis

Basis

A minimum of 92.8 percent of the thermal flow rate will pass through the fuel rod region of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes as well as the leakage from the core barrel-baffle region into the core are not considered effective for heat removal.

Discussion

Core cooling evaluations are based on the thermal flow rate (minimum flow) entering the reactor vessel. A maximum of 7.2 percent of this value is allotted as bypass flow. This includes rod cluster control (RCC) guide thimble cooling flow,

head cooling flow, baffle leakage, and leakage to the vessel outlet nozzle.

The maximum bypass flow fraction of 7.2 percent assumes no plugging devices or burnable absorbers in the RCC guide thimble tubes, which do not contain RCC rods.

4.4.1.4 Hydrodynamic Stability Design Bases

Basis

Modes of operation associated with Condition I and II events shall not lead to hydrodynamic instability.

4.4.1.5 Other Considerations

The above design bases together with the fuel clad and fuel assembly design bases given in Section 4.2.1.1 are sufficiently comprehensive so additional limits are not required.

Fuel rod diametral gap characteristics, moderator-coolant flow velocity and distribution, and moderator void are not inherently limiting. Each of these parameters is incorporated into the thermal and hydraulic models used to ensure the above mentioned design criteria are met. For instance, the fuel rod diametral gap characteristics change with time (see Section 4.2.1.3.1) and the fuel rod integrity is evaluated on that basis. The effect of the moderator flow velocity and distribution (see Section 4.4.2.3) and moderator void distribution (see Section 4.4.2.5) are included in the core thermal (THINC) evaluation and thus affect the design bases.

Meeting the fuel clad integrity criteria covers possible effects of clad temperature limitations. As noted in Section 4.2.1.3.1, the fuel rod conditions change with time. A single clad temperature limit for Condition I or Condition II events is not appropriate since of necessity it would be overly conservative. A clad temperature limit is applied to the loss-of-coolant accident (LOCA) (Section 15.3.1), control rod ejection accident (2), and locked rotor accident (3).

4.4.2 Description

4.4.2.1 Summary Comparison

The Salem Unit 1 and Unit 2 reactors are designed to the appropriate DNBR limit as well as no fuel centerline melting during normal operation, operational transients, and faults of moderate frequency. The values of the thermal and hydraulic design parameters are presented in Table 4.4-1, with comparisons between STD, Vantage 5H, Vantage+, and RFA. Values specific to Standard Thermal Design Procedure and Revised Thermal Design Procedure are provided where appropriate.

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The effects on DNB of fuel densification have been evaluated utilizing the methods and models described in detail in Reference 7 and summarized in the following sections. The net effect of fuel densification is a reduction of 0.2 percent in the DNBR due to a slight increase in the linear power generation rate as described in Section 4.4.2.2.

4.4.2.2 Fuel and Cladding Temperatures (Including Densification)

Consistent with the thermal-hydraulic design bases described in Section 4.4.1, the following discussion pertains mainly to fuel pellet temperature evaluation. A discussion of fuel clad integrity is presented in Section 4.2.1.3.1.

The thermal-hydraulic design assures that the maximum fuel temperature is below the melting point of UO_2 (melting point of 5080°F (1) unirradiated and decreasing 58°F per 10,000 MWD/MTU). To preclude center melting and as a basis for overpower protection system setpoints, a calculated centerline fuel temperature of 4700°F has been selected as the overpower limit. This provides sufficient margin for uncertainties in the thermal evaluations as described in Section 4.4.2.10.1. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, clad, gap, and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, etc, have been combined into a semi-empirical thermal model (see Section 4.2.1. 3.1) which includes a model for time dependent fuel densification described in References 7 and 108. This thermal model enables the determination of these factors and their net

effects on temperature profiles. The temperature predictions have been compared to inpile fuel temperature measurements (8 through 14) and melt radius data (15,16) with good results.

Effect of Fuel Densification on Fuel Rod Temperatures

Fuel densification results in fuel pellet shrinkage. This affects the fuel temperatures in the following ways:

1. Pellet radial shrinkage increases the pellet diametral gap which results in increased thermal resistance of the gap, and thus, higher fuel temperatures (See Section 4.2.1.3.1).

2. Pellet axial shrinkage may produce pellet to pellet gaps which result in local power spikes, described in Section 4.3.2.2.1 and thus, higher total heat flux hot channel factor, F_Q, and local fuel temperatures.

3. Pellet axial shrinkage will result in a fuel stack height reduction and an increase in the linear power generation rate (kW/ft) for a constant core power level. Using the methods described in Section 5.3 of Reference 7, the increase in linear power for the fuel rod specifications listed in Table 4.3-1 is 0.2 percent.

As described in Reference 7, fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are determined throughout the fuel rod lifetime with consideration of time dependent densification. Maximum fuel average and surface temperatures, shown on Figure 4.4-1 for standard fuel and Figure 4.4-1A for Vantage 5H, Vantage+, and RFA fuel as a function of linear power density (kW/ft), are peak values attained during the fuel lifetime. Figure 4.4-2 for standard fuel and Figure 4.4-2A for Vantage 5H, Vantage+, and RFA fuel present the peak value of fuel centerline temperature versus linear power density which is attained during the fuel lifetime.

The maximum pellet temperatures at the hot spot during full power steady state and at the maximum overpower trip point are shown in Table 4.4-1. The principal factors which are employed in the determination of the fuel temperature are discussed below.

4.4.2.2.1 Uranium Dioxide Thermal Conductivity

The thermal conductivity of UO_2 was evaluated from data reported in References 17 through 29.

At the higher temperatures, thermal conductivity is best obtained by utilizing the integral conductivity to melt which can be determined with more certainty. From an examination of the data, it has been concluded that the best estimate for the value of $\int_0^{2800°C} K dt$ is 93 watts/cm.

This conclusion is based on the integral values reported in References 15 and 29 through 33.

The design curve for the thermal conductivity is shown on Figure 4.4-3. The section of the curve at temperatures between 0°C and 1300°C is in excellent agreement with the recommendation of the International Atomic Energy Agency panel (34). The section of the curve above 1300°C is derived for an integral value of 93 watts/cm(15, 29, 33).

Thermal conductivity for UO_2 at 95 percent theoretical density can be represented best by the following equation:

$$K = \frac{1}{11.8 + 0.0238T} + 8.775 \times 10^{-13} T^3 \qquad (4.4\text{-}1)$$

where:

K = watts/cm-°C

T = °C.

4.4.2.2.2 Radial Power Distribution in UO_2 Fuel Rods

An accurate description of the radial power distribution as a function of burnup is needed for determining the power level for incipient fuel melting and other important performance parameters such as pellet thermal expansion, fuel swelling, and fission gas release rates.

This information on radial power distributions in UO_2 fuel rods is determined with the neutron transport theory code, LASER. The LASER code has been validated by comparing the code predictions on radial burnup and isotopic distributions with measured radial microdrill data (35,36). A "radial power depression factor", f, is determined using radial power distributions predicted by LASER. The factor f enters into the determination of the pellet centerline temperature, T_c, relative to the pellet surface temperature, T_s, through the expression:

$$\int_{T_s}^{T_c} k(T) \, dT = \frac{q'f}{4\pi} \qquad (4.4\text{-}2)$$

where:

k(T) = the thermal conductivity for UO with a uniform density distribution

q' = the linear power generation rate.

4.4.2.2.3 Gap Conductance

The temperature drop across the pellet-clad gap is a function of the gap size and the thermal conductivity of the gas in the gap. The gap conductance model is selected such that when combined with

clad temperature. Figure 4.4-4 shows the axial variation of average clad temperature for the average power rod both at beginning and end-of-life.

Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q, is defined by the ratio of the maximum to core average heat flux. As presented in Table 4.3-2 and discussed in Section 4.3.2.2.1, the design value F_Q for normal operation is 2.40, including fuel densification effects.

This results in peak local power of 13.1 kW/ft at full power conditions. As described in Section 4.3.2.2.6, the peak local power at the maximum overpower trip point is 21.1 kW/ft. The centerline temperature at this kW/ft must be below the UO_2 melt temperature over the lifetime of the rod, including allowances for uncertainties. The melt temperature of unirradiated UO_2 is 5080°F (1) and decreases by 58°F per 10,000 MWD/MTU. From Figure 4.4-2 for standard fuel and Figure 4.4-2A for Vantage 5H, Vantage+, and RFA fuel, it is evident that the centerline temperatures at the maximum overpower trip points for both units are far below those required to produce melting. Fuel centerline and average temperatures at rated (100 percent) power and at the maximum overpower trip point are presented in Table 4.4-1.

4.4.2.3 Critical Heat Flux Ratio or Departure from Nucleate Boiling Ratio and Mixing Technology

The minimum DNBRs for the rated power, design overpower, and anticipated transient conditions are given in Table 4.4-1. The core average DNBR is not a safety-related item as it is not directly related to the minimum DNBR in the core, which occurs at some elevation in the limiting flow channel. Similarly, the DNBR at the hot spot is not directly safety-related. The minimum DNBR in the limiting flow channel will be downstream of the peak

heat flux location (hot spot) due to the increased downstream enthalpy rise.

DNBRs are calculated by using the correlation and definitions described in the following Sections 4.4.2.3.1 and 4.4.2.3.2. The THINC-IV computer code (discussed in Section 4.4.3.4.1) is used to determine the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is discussed in Section 4.4.3.2.1 (nuclear hot channel factors) and in Section 4.4.2.3.4 (engineering hot channel factors).

4.4.2.3.1 Departure from Nucleate Boiling Technology

The primary DNB correlation used for the analysis of the Vantage 5H and Vantage+ fuel is the WRB-1 correlation (Reference 89). The Primary DNB correlation used for the analysis of the RFA fuel (with Intermediate flow Mixer grids) is the WRB-2 correlation (Reference 97).

The WRB-1 correlation was developed based exclusively on the large bank of mixing vane grid rod bundle CHF data (over 1100 points) that Westinghouse has collected. The WRB-1 correlation, based on local fluid conditions, represents the rod bundle data with better accuracy over a wide range of variables than the previous correlation used in design. This correlation accounts directly for both typical and thimble cold wall effects, uniform and non-uniform heat flux profiles, and variations in rod heated length and in grid spacing.

The Applicable range of parameters for the WRB-1 correlation is:

Pressure	:	$1440 \leq 2490$ psia
Local Mass Velocity	:	$0.9 \leq G_{loc}/10^6 \leq 3.7$ lb/ft^2-hr
Local Quality	:	$-0.2 \leq X_{loc} \leq 0.3$
Heated Length, Inlet to CHF Location	:	$L_h \leq 14$ feet
Grid Spacing	:	$13 \leq g_{sp} \leq 32$ inches
Equivalent Hydraulic Diameter	:	$0.37 \leq d_e \leq 0.60$ inches
Equivalent Heated Hydraulic Diameter	:	$0.46 \leq d_h \leq 0.59$ inches

Figure 4.4-5B shows measured critical heat flux plotted against predicted critical heat flux using the WRB-1 correlation.

A 95/95 correlation limit DNBR of 1.17 for the WRB-1 correlation has been approved by the NRC for Vantage 5H and Vantage+ fuel (Reference 92).

The WRB-2 DNB correclation was developed to take credit for the RFA Intermediate flow mixer (IFM) grid design. A limit of 1.17 is also applicable for the WRB-2 correlation. Figure 4.4-5C shows measured critical heat flux plotted against predicted critical heat flux using the WRB-2 correlation.

The applicable range of parameters for the WRB-2 correlation is

Pressure	:	$1440 \leq P \leq 2490$ psia
Local Mass Velocity	:	$0.9 \leq G_{loc}/10^6 \leq 3.7$ lb/ft^2-hr
Local Quality	:	$-0.1 \leq X_{loc} \leq 0.3$
Heated Length, Inlet to CHF Location	:	$L_h \leq 14$ feet
Grid Spacing	:	$10 \leq g_{sp} \leq 26$ inches
Equivalent Hydraulic Diameter	:	$0.33 \leq d_e \leq 0.51$ inches
Equivalent Heated Hydraulic Diameter	:	$0.45 \leq d_h \leq 0.66$ inches

The W-3 correlation (References 4 and 98) is used for all fuel types where the primary DNBR correlations are not applicable. The WRB-1 and WRB-2 correlations were developed based on mixing vane data and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 correlation, which does not take credit for mixing vane grids, is used to calculate the DNBR value in the heated region below the first mixing vane grid. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlations. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45, Reference 99. for system pressures greater than 1000 psia, the W-3 correlation limit is 1.30. A cold wall factor (Reference 100) is applied to the W-3 DNB correlation to account for the presence of the unheated thimble surfaces.

References 90 and 91 document the approval of the NRC that a 95/95 limit DNBR of 1.17 is appropriate for the STD and optimized fuel assemblies.

The use of the WRB-2 correlation with a 95/95 DNBR limit of 1.17 is applicable to the RFA fuel (References 111 and 112).

4.4.2.3.2 Definition of Departure from Nucleate Boiling Ratio

The DNB heat flux ratio (DNBR) as applied to the standard fuel utilizing the W-3 "R" grid DNB correlation when all flow cell walls are heated is:

$$DNBR = \frac{q''_{DNB,N} \times F'_S}{q''_{loc}} \qquad (4.4\text{-}5)$$

where:

$$q''_{DNB,N} = \frac{q''_{DNB,EU}}{F} \qquad (4.4\text{-}6)$$

and $q''_{DNB,EU}$ is the uniform DNB heat flux as predicted by the W-3 DNB correlation (42) when all flow cell walls are heated.

F is the flux shape factor to account for nonuniform axial heat flux distributions (42) with the "C" term modified as in Reference 39.

F'_S is the modified spacer factor described in Reference 5 using an axial grid spacing coefficient, K_S = 0.046, and a thermal diffusion coefficient (TDC) of 0.038, based on the 26-inch grid

the approach which was valid for the original W-3 DNB correlation is conservatively applicable for the "R" and 17 x 17 data (with the 0.88 multiplier for the 17 x 17 data).

Standard fuel will continue to be designed to a minimum DNBR of 1.30 for the peak rod or rods in the core. Based on the W-3 statistics, the proportion of such peak rods that will not reach DNB is 0.95 or greater at a 95 percent confidence level.

The DNB heat flux ratio (DNBR) as applied to the Vantage 5H and Vantage+ designs utilizing the WRB-1 DNB correlation, and as applied to the RFA design utilizing the WRB-2 DNB correlation is:

$$DNBR = \frac{q''_{DNB,\ N}}{q''_{loc}}$$

where:

$$q''_{DNB,N} = \frac{q''_{DNB,\ EU}}{F}$$

and $q''_{DNB,EU}$ is the uniform critical heat flux as predicted by the WRB-1 DNB correlation (Reference 89) or the WRB-2 correlation (Reference 97).

The procedures used in the evaluation of DNB margin for these applications show that the calculated minimum DNBR for the peak rod or rods in the core will be above the appropriate DNBR limit during Class I and II incidents, even when all the engineering hot channel factors described in Section 4.4.2.3.4 occur simultaneously in these channels. In reality the probability of this simultaneous occurrence is negligibly small, and substantial increases in local heat flux or coolant temperature could be tolerated without violation of the design basis.

4.4.2.3.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density, and flow velocity. The proportionality is expressed by the dimensionless thermal diffusion coefficient, (TDC), which is defined as:

$$TDC = \frac{w'}{\rho V a} \qquad (4.4\text{-}9)$$

where:

w' = flow exchange rate per unit length, lbs/ft-sec

ρ = fluid density, lbm/ft^3

V = fluid velocity, ft/sec

pressurized water reactor (PWR) core geometry, the value of TDC increased with quality to a point and then decreased, but never below the single phase value. Gonzalez, Santalo, and Griffith showed that the mixing coefficient increased as the void fraction increased.

The data from these tests on the "R" grid showed that a design TDC value of 0.038 (for 26-inch grid spacing) can be used in determin ing the effect of coolant mixing in the THINC analysis.

A mixing test program similar to the one described above was conducted at Columbia University for the 17 x 17 geometry and mixing vane grids on 26-inch spacing (50). The mean value of TDC obtained from these tests was 0.059, and all data was well above the current design value of 0.038.

Since the actual reactor grid spacing is approximately 20 inches for the Vantage 5H and Vantage+ designs, and approximately 10 inches for the RFA design, additional margin is available, as the value of TDC increases as grid spacing decreases (43).

4.4.2.3.4 Engineering Hot-Channel Factors

The total hot-channel factors for heat flux and enthalpy rise are defined as the maximum-to-core average ratios of these quantities. The heat flux hot-channel factor considers the local maximum linear heat generation rate at a point (the "hot spot"), and the enthalpy rise hot-channel factor involves the maximum integrated value along a channel (the "hot-channel").

Each of the total hot-channel factors considers a nuclear hot-channel factor (See Section 4.4.3.2) describing the neutron power distribution and an engineering hot-channel factor, which allows for variations in flow conditions and fabrication tolerances. The engineering hot-channel factors are made up of subfactors which account for the influence of the variations of fuel pellet diameter, density, enrichment, and eccentricity; fuel

rod diameter, pitch, and bowing; inlet flow distribution; flow redistribution; and flow mixing.

Heat Flux Engineering Hot-Channel Factor, F_Q^E

The heat flux engineering hot channel factor is used to evaluate the maximum liners heat generation rate of the core. This subfactor is determined by statistically combining the fabrication variations for fuel pellet diameter, density, and enrichment has a value of 1.03 at the 95 percent probability level with 95 percent confidence. As shown in Reference 15, no DNB penalty need be taken for the short, relatively low-intensity heat flux spikes caused by variations in the above parameters, as well as fuel pellet eccentricity and fuel rod diameter variation.

Enthalpy Rise Engineering Hot-Channel Factor, $F_{\Delta H}^E$

The effect of variations in flow conditions and fabrication tolerances on the hot-channel enthalpy rise is directly considered in the THINC core thermal subchannel analysis (See Section 4.4.3.4.1) under any reactor operating condition. The items considered contributing to the enthalpy rise engineering hot-channel factor are discussed below:

Pellet Diameter, Density and Enrichment

Variations in pellet diameter, density, and enrichment are considered statistically in establishing the limit DNBRs (see paragraph 4.4.1.1) for the Revised Thermal Design Procedure (Reference 96) employed in this application. Uncertainties in these variables are determined from sampling of manufacturing data.

(This text has been deleted)

Inlet Flow Maldistribution

The consideration of inlet flow maldistribution in core thermal performances is discussed in Section 4.4.3.1.2. A design basis of 5 percent reduction in coolant flow to the hot assembly is used in the THINC-IV analysis.

Flow Redistribution

The flow redistribution accounts for the reduction in flow in the hot-channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the nonuniform power distribution is inherently considered in the THINC analysis for every operating condition which is evaluated.

Flow Mixing

The subchannel mixing model incorporated in the THINC Code and used in reactor design is based on experimental data (51) discussed in Section 4.4.3.4.1. The mixing vanes incorporated in the spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot-channel resulting from local power peaking or unfavorable mechanical tolerances.

4.4.2.3.5 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in Reference 93, must be accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of the DNBR and/or margin obtained from measured plant operating parameters (such as $F^N_{\Delta H}$ or core flow) -- which are less limiting than those required by the plant safety analysis -- can be used to offset the effect of rod bow.

For the safety analysis of the Salem units, sufficient DNBR margin was maintained (see Paragraph 4.4.1.1) to accommodate the full and low flow rod bow DNBR penalties identified in Reference 94. The referenced penalties are applicable to the Vantage 5H and Vantage+ fuel assembly analyses using the WRB-1 DNB correlation and to RFA assembly analyses using the WRB-2 DNB correlation.

This penalty is the maximum rod bow penalty at an assembly average burnup of 24,000 MWD/MTU. For burnups greater than 24,000 MWD/MTU, credit is taken for the effect of $F_{\Delta H}$ burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory. Therefore, no additional rod bow penalty is required at burnups greater than 24,000 MWD/MTU.

In the upper spans of the RFA fuel assembly, additional restraint is provided with the Intermediate Flow Mixer (IFM) grids such that the grid-to-grid spacing in those spans with IFM grids is approximately 10 inches compared to approximately 20 inches in the other spans. Using the NRC approved scaling factor results in predicted channel closure in the limiting 10 inch spans of less than 50 percent closure. Therefore, no rod bow DNBR penalty is required in the 10 inch spans of the RFA safety analyses.

The introduction of new fuel assembly design features in a core reload will result in mixed cores. It can typically take two or three cycles to completely transition to a full core of similar fuel assembly features. Generally, mixed (or transition) core impacts are a result of differences in pressure drop and localized flow distribution between adjacent assemblies with different grid types. The Westinghouse transition core DNB methodology is described in References 101, 102 and 103.

The transition from the 17 x 17 Standard design to Vantage 5H has been previously evaluated in References 104 and 105. With the implementation of the RFA design, IFM grids will be located in spans between the mid grids, where no grids exist in the Vantage 5H or Vantage+ assemblies. Test and analyses have confirmed that the RFA design is hydraulically compatible with the Vantage 5H and Vantage+ fuel designs (References 97, 111 and 115).

Transition cores are analyzed as if they were full cores of one assembly type (full core of Vantage 5H or RFA) and applying an applicable transition core DNBR penalty (Reference 106). The transition core DNBR penalty is a function of the number of new type fuel assemblies in the core. Therefore, the penalty is reduced each subsequent cycle. Since the Vantage+ assembly is dimensionally and hydraulically identical to Vantage 5H, introduction of this design resulted in no transition impact.

4.4.2.4 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by some asymmetric perturbation. A dropped or misaligned rod cluster control assembly (RCCA) could cause changes in hot-channel factors; however, these events are analyzed separately in Section 15. This discussion will be confined to flux tilts caused by x-y xenon transients, inlet temperature mismatches, enrichment variations within tolerances, etc.

The design value of the enthalpy rise hot-channel factor $F^N\Delta H$, which includes an 8 percent uncertainty (as discussed in Section 4.3.2.2.7) is assumed to be sufficiently conservative that flux tilts up to and including the alarm point (see Section 16.3.10, Technical Specifications) will not result in values of greater than that assumed in this submittal. The design value of F_Q does not include a specific allowance for quadrant flux tilts.

4.4.2.5 Void Fraction Distribution

The calculated core average and the hot-subchannel maximum and average void fractions are presented in Table 4.4-3 for operation at full power with design hot-channel factors. The void fraction distribution in the core at various radial and axial locations is presented in Reference 52. The void models used in the THINC-IV computer code are described in Section 4.4.2.8.3.

Since void formation due to subcooled boiling is an important promoter of interassembly flow redistribution, a sensitivity study was performed with THINC-IV using the void model referenced above (52)

The results of this study showed that because of the realistic crossflow model used in THINC-IV, the minimum DNBR in the hot-channel is relatively insensitive to variations in this model.

The range of variations considered in this sensitivity study covered the maximum uncertainty range of the data used to develop each part of the void fraction correlation.

4.4.2.6 Core Coolant Flow Distribution

Assembly average coolant mass velocity and enthalpy at various radial and axial core locations are given below. Coolant enthalpy rise and normalized core flow distributions are shown for the 4-foot elevation (1/3 of core height) on Figure 4.4-7, and 8-foot elevation (2/3 of core height) on Figure 4.4-8, and at the core exit on Figure 4.4-9. These distributions are for the full power conditions as given in Table 4.4-1 and for the radial power density distribution shown on Figure 4.3-7. The THINC Code analysis for this case utilized a uniform core inlet enthalpy and inlet flow distribution.

4.4.2.7 Core Pressure Drops and Hydraulic Loads

4.4.2.7.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops shown in Table 4.4-1 are described in Section 4.4.2.8. The core pressure drop includes the eight grid fuel assembly, core support plate, and holddown plate pressure drops. The full power operation pressure drop values shown in the tables are the unrecoverable pressure drops across the vessel, including the inlet and outlet nozzles, and across the core. These pressure drops are based on the best estimate flow (most likely value for actual plant operating conditions) as described in Section 5.1.1. Section 5.1.1 also defines and describes the thermal design flow (minimum flow) which is the basis for reactor core thermal performance and the mechanical design flow (maximum flow) which is used in the mechanical design of the reactor vessel internals and fuel assemblies. Since the best estimate flow is that flow which is most likely to exist in an operating plant, the

calculated core pressure drops in Table 4.4-1 are based on this best estimate flow rather than the thermal design flow.

Uncertainties associated with the core pressure drop values are discussed in Section 4.4.2.10.

4.4.2.7.2 Hydraulic Loads

The fuel assembly holddown springs, Figure 4.2-2, are designed to keep the fuel assemblies in contact with the lower core plate under all Condition I and II events with the exception of the turbine overspeed transient associated with a loss-of-external load. The holddown springs are designed to tolerate the possibility of an over deflection associated with fuel assembly liftoff for this case and provide contact between the fuel assembly and the lower core plate following this transient. More adverse flow conditions occur during a LOCA as discussed in Section 15.

Hydraulic loads at normal operating conditions are calculated considering the mechanical design flow which is described in Section 5.1 and accounting for the minimum core bypass flow based on manufacturing tolerances. Core hydraulic loads at cold plant startup conditions are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, which create flow rates 20 percent greater than the mechanical design flow, are evaluated to be greater than twice the fuel assembly weight.

Core hydraulic loads were measured during the prototype assembly tests described in Section 1.5. Reference 6 contains a detailed discussion of the results.

The Vantage 5H, Vantage+ and RFA designs have been shown to be hydraulically compatible in References 111 and 115.

4.4.2.8 Correlation and Physical Data

4.4.2.8.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the familiar Dittus-Boelter correlation (53), with the properties evaluated at bulk fluid conditions:

$$\frac{hD_e}{K} = 0.023\left(\frac{D_e G}{\mu}\right)^{0.8}\left(\frac{C_p \mu}{K}\right)^{0.4} \qquad (4.4\text{-}10)$$

where:

h	=	heat transfer coefficient, Btu/hr-ft^2-°F
De	=	equivalent diameter, ft
K	=	thermal conductivity, Btu/hr-ft^2-°F
G	=	mass velocity, lb/hr-ft^2
μ	=	dynamic viscosity, lb/ft-hr
C_p	=	heat capacity, Btu/lb-°F

This correlation has been shown to be conservative (54) for rod bundle geometries with pitch to diameter ratios in the range used by PWRs.

The onset of nucleate boiling occurs when the clad wall temperature reaches the amount of superheat predicted by Thom's (55) correlation. After this occurrence the outer clad wall temperature is determined by:

$$\Delta T_{sat} = (0.072 \exp(-P/1260))\,(q'')^{0.5} \qquad (4.4\text{-}11)$$

where:

ΔT_{sat} = wall superheat, $T_w - T_{sat}$, °F

q'' = wall heat flux, Btu/hr-ft^2

P = pressure, psia

T_w = outer clad wall temperature, °F

T_{sat} = saturation temperature of coolant at P, °F

4.4.2.8.2 Total Core and Vessel Pressure Drop

Unrecoverable pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flow path. The flow field is assumed to be incompressible, turbulent, single-phase water. These assumptions apply to the core and vessel pressure drop calculations for the purpose of establishing the primary loop flow rate. Two-phase considerations are neglected in the vessel pressure drop evaluation because the core average void is negligible (See Section 4.4.2.5 and Table 4.4-3. Two phase flow considerations in the core thermal subchannel analyses are considered and the models are discussed in Section 4.4.3.1.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = \left(K + F \frac{L}{D_e}\right) \frac{\rho V^2}{2 g_c (144)} \qquad (4.4\text{-}12)$$

where:

ΔP_L = unrecoverable pressure drop, lb_f/in^2

ρ = fluid density, lb_m/ft^3

L = length, ft

D_e = equivalent diameter, ft

V = fluid velocity, ft/sec

The thermal response of the fuel rod is discussed in Section 4.4.3.7.

4.4.2.10 Uncertainties in Estimates

4.4.2.10.1 Uncertainties in Fuel and Clad Temperatures

As discussed in Section 4.4.2.2, the fuel temperature is a function of crud, oxide, clad, gap, and pellet conductances. Uncertainties in the fuel temperature calculation are essentially of two types: fabrication uncertainties such as variations in the pellet and clad dimensions and the pellet density; and model uncertainties such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified by comparison of the thermal model to the inpile thermocouple measurements (8 through 14), by out-of-pile measurements of the fuel and clad properties (17 through 28), and by measurements of the fuel and clad dimensions during fabrication. The resulting uncertainties are then used in all evaluations involving the fuel temperature. The effect of densification on fuel temperature uncertainties is presented in Reference 7 and also included in the calculation of total uncertainty.

In addition to the temperature uncertainty described above, the measurement uncertainty in determining the local power, and the effect of density and enrichment variations on the local power are considered in establishing the heat flux hot-channel factor. These uncertainties are described in Section 4.3.2.2.

Reactor trip setpoints as specified in the Technical Specifications include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift, and channel reproducibility, temperature measurement uncertainties, noise, and heat capacity variations.

Uncertainty in determining the cladding temperature results from uncertainties in the crud and oxide thicknesses. Because of the excellent heat transfer between the surface of the rod and the

coolant, the film temperature drop does not appreciably contribute to the uncertainty.

4.4.2.10.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best estimate flow, as discussed in Section 5.1, are quoted in Table 4.4-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

A major use of the core and vessel pressure drops is to determine the primary system coolant flow rates as discussed in Section 5.1. In addition, as discussed in Section 4.4.4.1, tests on the primary system prior to initial criticality will be made to verify that a conservative primary system coolant flow rate has been used in the design and analyses of the plant.

4.4.2.10.3 Uncertainties Due to Inlet Flow Maldistribution

The effects of uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses are discussed in Section 4.4.3.1.2.

4.4.2.10.4 Uncertainty in DNB Correlation

The uncertainty in the DNB correlation (Section 4.4.2.3) can be written as a statement on the probability of not being in DNB based on the statistics of the DNB data. This is discussed in Section 4.4.2.3.2.

4.4.2.10.5 Uncertainties in DNBR Calculations

The uncertainties in the DNBRs calculated by THINC analysis (see Section 4.4.3.4.1) due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors and including measurement error

Allowances in the statistical evaluation of the DNBR limit (see paragraph 4.4.1.1) using the Revised Thermal Design Procedure (Reference 96). In addition, conservative values for the engineering hot channel factors are used as discussed in Section 4.4.2.3.4.

The results of a sensitivity study (52) with THINC-IV show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F^N_{\Delta H}$).

The ability of the THINC-IV computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in Section 4.4.3.4.1 and in Reference 63. Studies have been performed (52) to determine the sensitivity of the minimum DNBR in the hot-channel to the void fraction correlation (also see Section 4.4.2.8.3); the inlet velocity and exit pressure distributions assumed as boundary conditions for the analysis; and the grid pressure loss coefficients. The results of these studies show that the minimum DNBR in the hot channel is relatively insensitive to variations in these parameters. The range of variations considered in these studies covered the range of possible variations in these parameters.

4.4.2.10.6 Uncertainties in Flow Rates

The uncertainties associated with loop flow rates are discussed in Section 5.1. For core thermal performance evaluations, a thermal design loop flow is used which is less than the best estimate loop flow (approximately 4 percent). In addition, another 7.2 percent of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available vessel flow paths described in Section 4.4.3.1.1.

4.4.2.10.7 Uncertainties in Hydraulic Loads

As discussed in Section 4.4.2.7.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient which creates flow rates 20 percent greater than the mechanical design

flow. The mechanical design flow is greater than the best estimate or most likely flow rate value for the actual plant operating condition.

4.4.2.10.8 Uncertainty in Mixing Coefficient

The value of the mixing coefficient, TDC, used in THINC analyses for this application is 0.038. The mean value of TDC obtained in the "R" grid mixing tests described in Section 4.4.2.3.3 was 0.042 (for 26-inch grid spacing). The value of 0.038 is one standard deviation below the mean value, and ≅ 90 percent of the data gives values of TDC greater than 0.038 (43).

The results of the mixing tests done on 17 x 17 geometry, as discussed in Section 4.4.2.3.3, had a mean value of TDC of 0.059 and standard deviation of $\sigma = 0.007$. Hence the current design value of TDC is almost 3 standard deviations below the mean for 26-inch grid spacing.

4.4.2.11 Plant Configuration Data

Plant configuration data for the thermal-hydraulic and fluid systems external to the core are provided in the appropriate Sections 5, 6, and 9. Implementation of the ECCS is discussed in Section 15. Some specific areas of interest are the following:

1. Total coolant flow rates for the RCS are provided in Table 5.1-1. Flow rates employed in the evaluation of the core are presented in Section 4.4.

2. Total RCS volume including pressurizer and surge line, RCS liquid volume including pressurizer water at steady state power conditions are given in Table 5.1-1.

3. The flow path length through each volume may be calculated from physical data provided in the above referenced tables.

4. The height of fluid in each component of the RCS may be determined from the physical data presented in Section 5.5. The components of the RCS are water filled during power operation with the pressurizer being approximately 60 percent water filled.

5. The elevation of components of the RCS relative to the reactor vessel are shown in Section 5.1. Components of the ECCS are to be located so as to meet the criteria for net positive suction head (NPSH) described in Section 6.1.

6. Line lengths and sizes for the Safety Injection System are determined so as to guarantee a total system resistance which will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Section 15.

4.4.3 Evaluation

4.4.3.1 Core Hydraulics

4.4.3.1.1 Flow Paths Considered in Core Pressure Drop and Thermal Design

The following flow paths or core bypass flow are considered:

1. Flow through the spray nozzles into the upper head for head cooling purposes

2. Flow entering into the RCC guide thimbles to cool the control rods

3. Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between the vessel and the barrel

4. Flow entering into the core from the baffle-barrel region through the gaps between the baffle plates

The above contributions are evaluated to confirm that the design value of core bypass flow is met. The design value of core bypass flow for Salem Units 1 and 2 is equal to 7.2 percent of the total vessel flow. Of the total allowance, 4.0 percent is associated with the core and the remainder associated with the internals. Calculations have been performed accounting for drawing tolerances and uncertainties in pressure losses. Based on these calculations, the core bypass flow for Salem Units 1 and 2 is no greater than the value quoted above.

Flow model test results for the flow path through the reactor are discussed in Section 4.4.2.8.2.

4.4.3.1.2 Inlet Flow Distributions

Data has been considered from several 1/7 scale hydraulic reactor model tests (56,57,64) in arriving at the core inlet flow maldistribution criteria to be used in the THINC analyses (See Section 4.4.3.4.1). THINC-I analyses made using this data have indicated that a conservative design basis is to consider a 5 percent reduction in the flow to the hot assembly (65). The same design basis of 5 percent reduction to the hot assembly inlet is used in THINC-IV analyses.

The experimental error estimated in the inlet velocity distribution has been considered as outlined in Reference 52 where the sensitivity of changes in inlet velocity distributions to hot channel thermal performance is shown to be small. Studies (52) made with the improved THINC model (THINC-IV) show that it is adequate to use the 5 percent reduction in inlet flow to the hot

assembly for a loop out of service based on the experimental data in References 56 and 57.

The effect of the total flow rate on the inlet velocity distribution was studied in the experiments of Reference 56. As was expected, on the basis of the theoretical analysis, no significant variation could be found in inlet velocity distribution with reduced flow rate.

(This text has been deleted)

4.4.3.1.3 Empirical Friction Factor Correlations

Two empirical friction factor correlations are used in the THINC-IV computer code (described in Section 4.4.3.4.1).

The friction factor in the axial direction, parallel to the fuel rod axis, is evaluated using the Novendstern-Sandberg correlation (66). This correlation consists of the following:

1. For isothermal conditions, this correlation uses the Moody (59) friction factor including surface roughness effects.

2. Under single-phase heating conditions a factor is applied based on the values of the coolant density and viscosity at the temperature of the heated surface and at the bulk coolant temperature.

3. Under two-phase flow conditions the homogeneous flow model proposed by Owens (67) is used with a modification to account for a mass velocity and heat flux effect.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chik (58) is applicable. This correlation is of the form:

$$F_L = A \, \mathrm{Re}_L^{-0.2} \qquad (4.4\text{-}13)$$

where:

A is a function of the rod pitch and diameter as given in Reference 58.

Re_L is the lateral Reynolds number based on the rod diameter.

Extensive comparisons of THINC-IV predictions using these correlations to experimental data are given in Reference 63, and verify the applicability of these correlations in PWR design.

4.4.3.2 Influence of Power Distribution

The core power distribution which is largely established at beginning of life by fuel enrichment, loading pattern, and core power level is also a function of variables such as control rod worth and position, and fuel depletion throughout lifetime. Radial power distributions in various planes of the core are often illustrated for general interest; however, the core radial enthalpy rise distribution as determined by the integral of power up each channel is of greater importance for DNB analyses. These radial power distributions, characterized by $F^N_{\Delta H}$ (defined in Section 4.3.2.2.2) as well as axial heat flux profiles are discussed in the following two sections.

4.4.3.2.1 Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$.

Given the local power density q' (kw/ft) at a point x, y, z in a core with N fuel rods and height H,

$$F^N_{\Delta H} = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max} \int_0^H q'(x,y,z)\,dz}{\frac{1}{n}\sum_{\text{all rods}} \int_0^H q'(x,y,z)\,dz} \qquad (4.4\text{-}14)$$

where:

x_o, y_o are the position coordinates of the hot rod.

The way in which $F^N_{\Delta H}$ is used in the DNB calculation is important. The location of minimum DNBR depends on the axial profile and the value of DNBR depends on the enthalpy rise to that point. Basically, the maximum value of the rod integral is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained which, when normalized to the design value of $F^N_{\Delta H}$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers which are typical of distributions found in hot assemblies. In this manner worst case axial profiles can be combined with worst case radial distributions for reference DNB calculations.

It should be noted again that $F^N_{\Delta H}$ is an integral and is used as such in the DNB calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core. The sensitivity of the THINC-IV analysis to radial power shapes is discussed in Reference 52.

For operation at a fraction P of full power, the design $F^N_{\Delta H}$ used is given by:

$$F^N_{\Delta H} = 1.65\ (1 + 0.3\ (1-P)) \qquad (4.4\text{-}15)$$

The permitted relaxation of $F^N_{\Delta H}$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits (68,88), thus allowing greater flexibility in the nuclear design.

4.4.3.2.2 Axial Heat Flux Distributions

As discussed in Section 4.3.2.2, the axial heat flux distribution can vary as a result of rod motion, power change, or due to spatial xenon transients which may occur in the axial direction. Consequently, it is necessary to measure the axial power imbalance by means of the ex-core nuclear detectors (as discussed in Section 4.3.2.2.7) and protect the core from excessive axial power imbalance. The Reactor Trip System provides automatic reduction of the trip setpoint in the overtemperature ΔT channels on excessive axial power imbalance; that is, when an extremely large axial offset corresponds to an axial shape which could lead to a DNBR which is less than that calculated for the reference DNB design axial shape.

The reference DNB design axial shape used for the Reactor Trip System application is a chopped cosine shape with a peak average value of 1.55.

4.4.3.3 Core Thermal Response

A general summary of the steady-state thermal-hydraulic design parameters including thermal output, flow rates, etc, is provided in Table 4.4-1 for all loops in operation.

DNB With Return to Nucleate Boiling - Additional DNB tests have been conducted by Westinghouse (84) in 19 and 21 rod bundles. In these tests, DNB without physical burnout was experienced more than once on single rods in the bundles for short periods of time. Each time, a reduction in power of approximately 10 percent was sufficient to reestablish nucleate boiling on the surface of the rod. During these and subsequent tests, no adverse effects were observed on this rod or any other rod in the bundle as a consequence of operating in DNB.

4.4.3.9 Energy Release or Rupture of Waterlogged Fuel Elements

A full discussion of waterlogging, including energy release, is contained in Section 4.4.3.6. It is noted that the resulting energy release is not expected to affect neighboring fuel rods.

4.4.3.10 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockages can occur within the coolant channels of a fuel assembly or external to the reactor core. The effects of fuel assembly blockage within the assembly on fuel rod behavior are more pronounced than external blockages of the same magnitude. In both cases the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, where it occurs in the reactor, and how far along the flow stream the reduction persists are considerations which will influence the fuel rod behavior. The effects of coolant flow blockages in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as computer programs similar to the THINC-IV program. Inspection of the DNB correlation (Section 4.4.2.3 and References 42, 98, 97 and 113) shows that the predicted DNBR is dependent upon the local values of quality and mass velocity.

The THINC-IV code is capable of predicting the effects of local flow blockages on DNBR within the fuel assembly on a subchannel basis, regardless of where the flow blockage occurs. In Reference

63, it is shown that for a fuel assembly similar to the Westinghouse design, THINC-IV accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked. Full recovery of the flow was found to occur about 30 inches downstream of the blockage. With the reference reactor operating at the nominal full power conditions specified in Table 4.4-1 the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the reactor reaching the DNBR limit.

From a review of the open literature it is concluded that flow blockage in "open lattice cores" similar to the Westinghouse cores causes flow perturbations which are local to the blockage. For instance, A. Oktsubo et al (85) show that the mean bundle velocity is approached asymptotically about 4 inches downstream from a flow blockage in a single flow cell. Similar results were also found for 2 and 3 cells completely blocked. Basmer et al (86) tested an open lattice fuel assembly in which 41 percent of the subchannels were completely blocked in the center of the test bundle between spacer grids. Their results show the stagnant zone behind the flow blockage essentially disappears after 1.65 L/De or about 5 inches for their test bundle. They also found that leakage flow through the blockage tended to shorten the stagnant zone or in essence the complete recovery length. Thus, local flow blockages within a fuel assembly have little effect on subchannel enthalpy rise. The reduction in local mass velocity is then the main parameter which affects the DNBR. If the Salem Units 1 and 2 were operating at full power and nominal steady state conditions as specified in Table 4.4-1, a reduction in local mass velocity of 60 percent in the Vantage 5H and Vantage+ fuel and 80 percent in the RFA fuel would be required to reduce the DNBR to the DNBR limit. The above mass velocity effect on the DNB correlation was based on the assumption of fully developed flow along the full channel length. In reality a local flow blockage is expected to promote turbulence and thus would likely not affect DNBR at all.

94. "Partial Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," letter, E. P. Rahe, Jr. (Westinghouse to J. R. Miller (NRC), NS-EPR-2515, dated October 9, 1981; "Remaining Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," letter, E. P. Rahe, Jr. (Westinghouse) to J. R. Miller (NRC), NS-EPR-2572, dated March 16, 1982.

95. Letter from C. Berlinger (NRC) to E. P. Rahe, Jr. (Westinghouse), "Request for Reduction in Fuel Assembly Burnup Limit for Calculation of Maximum Rod Bow Penalty," June 18, 1986.

96. Friedland, A. J. and Ray, S., ''Revised Thermal Design Procedure,'' WCAP-11397-P-A, April 1989.

97. Davidson, S. L. and Kramer, W. R. (Ed.), ''Reference Core Report VANTAGE 5 Fuel Assembly,'' WCAP-10444-P-A, September 1985.

98. Tong, L. S., ''Critical Heat Fluxes in Rod Bundles, Two Phase Flow and Heat Transfer in Rod Bundles,'' Annual Winter Meeting ASME, November 1968, p. 3146.

99. Letter from A. C. Thadani (NRC) to W. J. Johnson (Westinghouse), ''Acceptance for Referencing of Licensing Topical Report, WCAP-9226-P/9227-NP, 'Reactor Core Response to Excessive Secondary Steam Releases','' January 31, 1989.

100. Motley, F. E., Cadek, F. F., ''DNB Test Results for R-Grid Thimble Cold Wall Cells,'' WCAP-7695-L, Addendum 1, October 1972.

101. Davidson, S. L. and Iorii, J. A., ''Reference Core Report - 17x17 Optimized Fuel Assembly,'' WCAP-9500-A, May 1982.

102. Letter from E. P. Rahe (Westinghouse) to Miller (NRC) dated March 19, 1982, NS-EPR-2573, WCAP-9500 and WCAPS-9401/9402 NRC SER Mixed Core Compatibility Items.

103. Letter from C. O. Thomas (NRC) to Rahe (Westinghouse), ''Supplemental Acceptance No. 2 for Referencing Topical Report WCAP-9500," January 1983.

104. Letter from W. J. Johnson (Westinghouse) to M. W. Hodges (NRC), '' VANTAGE 5 DNB Transition Core Effects.'' NS-NRC-87-3268, October 2, 1987.a

105. Letter from M. W. Hodges (NRC) to W. J. Johnson (Westinghouse), NRC SER on VANTAGE 5 Transition Core Effects, February 24, 1998.

106. Schueren, P. and McAtee, K. R., ''Extension of Methodology for Calculating Transition Core DNBR Penalties,'' WCAP-11837-P-A, January 1990.

107. Letter from C. Berlinger)NRC) to E. P. Rahe Jr. (Westinghouse), ''Request for reduction in Fuel Assembly Burnup Limit Calculation of Maximum Rod Bow Penalty,'' June 18, 1986.

108. Weiner, R. A., et al., ''Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations,'' WCAP-10851-P-A, August 1988.

109. Leech, W. J., et al., ''Revised PAD Code Thermal Safety Model,'' WCAP-8720, Addendum 2, October 1982.

110. Friedland, A. J. and Ray, S., ''Improved THINC IV Modeling for PWR Core Design,'' WCAP-12330-P-A.

111. Davidson, S. L., Nuhfer, D. L. (Eds.), ''VANTAGE + Fuel Assembly Reference Core Report,'' WCAP-12610 and Appendices A through D, June 1990.

112. Letter from A. C. Thadani (NRC) to S. R. Tritch (Westinghouse). ''Acceptance for Referencing Topical Report WCAP-12610 '.), " VANTAGE + Fuel Assembly Reference Core Report','' July 1, 1991.

113. Motley, F. E., et al., ''New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids,'' WCAP-8762-P, July 1984.

114. C. F. Ciocca, ''Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology for Salem Units 1 & 2,'' WCAP-13651 (Proprietary), August 1993.

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Pressurizer

The pressurizer (Figure 5.1-2) provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for control purposes.

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle, relief and safety valve connections are located in the top head of the vessel. The heaters are removable for maintenance or replacement.

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line, which is attached to the bottom of the pressurizer, connects the pressurizer to the hot leg of a reactor coolant loop.

Pressurizer Relief Tank

The pressurizer relief tank condenses and cools the discharge from the pressurizer safety and relief valves as well as several smaller relief valves. The tank normally contains water in a predominantly nitrogen atmosphere; however, provisions are made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

The pressurizer relief tank, by means of its connection to the Waste Disposal System, provides a means for removing any noncondensable gases from the RCS which might collect in the pressurizer vessel.

Steam enters the tank through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature. The tank is equipped with an internal spray and a drain which are used to cool the tank

following a discharge. The tank is protected against overpressurization by two rupture discs which discharge into the reactor containment. The tank is carbon steel with a corrosion-resistant coating on the wetted surfaces. A flanged nozzle is provided on the tank for the pressurizer discharge line connection. This nozzle and the discharge piping and sparger within the vessel are austenitic stainless steel.

Steam Generators

The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet. Manways are provided for access to both sides of the divided head. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The units are primarily carbon steel. The heat transfer tubes are Inconel, the primary side of the tube sheets are clad with Inconel, and the interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. A Unit 2 steam generator (Series 51) is shown on Figure 5.1-3, and a Unit 1 replacement steam generator (Model F) is shown in Figure 5.1-3A.

Reactor Coolant Pumps

Each reactor coolant loop contains a vertical single stage mixed flow pump which employs a controlled leakage seal assembly. The pump is shown on Figure 5.1-4 and net positive suction head characteristics are shown on Figure 5.1-5.

Reactor coolant is drawn up through the primary pump impeller, discharged through passages in the diffuser and out through a discharge nozzle in the side of the casing. The rotor-impeller can be removed from the casing for maintenance or inspection without removing the casing from the piping. All parts of the

pump in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

Reactor Coolant Piping

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. All smaller piping which comprise part of the RCS boundary, such as the pressurizer surge line, spray and relief lines, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer relief and the pressurizer code safety valves, where flanged joints are used. Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients.

Valves

All valves in the RCS which are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant are special materials, such as hard surfacing and packing.

All RCS valves, (except as listed below), which contain radioactive fluid and which normally operate above 212°F, are provided with double-packed stuffing boxes and stem intermediate lantern gland leakoff connections. All throttling control valves, regardless of size, (except as listed below), are provided with double-packed stuffing boxes and with stem leakoff connections. All leakoff connections are piped to the reactor coolant drain tank or pressurizer relief tank.

The valves listed below have a single set packing configuration and inactive leakoff lines.

Salem #1			Salem #2		
1PS1	1PS25	1PR6	2PS1	2PS25	2PR6
1PS3	1PS28	1PR7	2PS3	2PS28	2PR7
1PS24	1PS29		2PS24	2PS29	

Reactor Coolant System High Point Venting

Venting of the RCS during abnormal conditions permits removal of noncondensable gases, thereby aiding natural circulation flow.

There are three principal high points in the RCS: the pressurizer, the reactor vessel head, and the steam generator tube bundle invert.

The pressurizer power-operated relief valve serves as a vent and provides remote venting capability from the control room. This vent is safety grade and meets the single failure criterion.

The high points created by the tube bundle in the steam generator cannot be vented at that location. A Westinghouse study (1) has concluded, however, that only a small amount of noncondensables would be present during any transient which would depend significantly on the steam generators for decay heat removal. It further concluded that the presence of a small amount of noncondensables would not significantly impact natural circulation in the system.

The reactor vessel is vented though a piping system connected to the part-length control rod drive mechanism (CRDM) nearest to the center of the vessel head. As shown in the RCS flow diagram (Figures 5.1-6A and B), the vessel head can be vented either to the pressurizer relief tank or to the containment.

The existing lead screw in the part-length CRDM was removed prior to using it as a connection for head vent. The connection from this part-length CRDM cap (cap with a 0.815-inch diameter hole) is through a 1-inch Schedule 160 pipe connection and includes a 11/32-inch diameter orifice close to the reactor vessel. The vent then runs to the pressurizer relief tank through a redundant grouping of solenoid valves. Break flanges are provided to allow the reactor vessel head removal and to provide room for the manipulator crane movement. The piping is supported to Seismic Category I requirements to ensure that allowable loadings on the part-length CRDM housing are not exceeded. The piping and valves are stainless steel.

i.e., an insurge followed by an outsurge. It is assumed that the spray valve opens to admit spray water into the pressurizer once at the design flowrate for each design step change in plant load. Thus the number of occurrences for the spray nozzle corresponds to that shown for the other components listed in Table 5.2-10.

During plant cooldown, spray water is introduced into the pressurizer to cool down the pressurizer. The maximum pressurizer cooldown rate is specified at 200°F per hour which is twice the rate specified for the other RCS components.

5.2.1.5.13 Accident Conditions

The effect of the accident loading was evaluated in combination with normal loads to demonstrate the adequacy to meet the stated plant safety criteria.

A brief description of each accident transient that was considered follows. In each case, one occurrence was evaluated.

Reactor Coolant Pipe Break

This accident involves the rupture of a RCS pipe resulting in a loss of primary coolant. It is conservatively assumed that the system pressure and temperature are reduced rapidly and the Safety Injection System (SIS) is initiated to introduce 70°F water into the RCS. The safety injection signal also results in a turbine and reactor trip. Because of the rapid blowdown of coolant from the system and the comparatively large heat capacity of the metal sections of the components, it is likely that the metal is still at no-load temperature conditions when the 70°F safety injection water is introduced into the system.

Steam Line Break

For component evaluation, the following conservative conditions were considered:

1. The reactor is initially in a hot, zero-load, just critical condition assuming all rods in except the most reactive rod which is assumed to be stuck in its fully withdrawn position.

2. A steam line break occurs inside the containment resulting in a reactor and turbine trip.

3. Subsequent to the break, there is no return to power and the reactor coolant temperature cools down to 212°F.

4. The ECCS pumps restore the reactor coolant pressure to 2500 psia.

The above conditions result in the most severe temperature and pressure variations which the component will encounter during a steam break accident. Both Series 51 (Unit 2) and Model F (Unit 1) are qualified for the given conditions.

Steam Generator Tube Rupture

This accident postulates the double-ended rupture of a steam generator tube resulting in a decrease in pressurizer level and reactor coolant pressure. Reactor trip will typically occur due to a safety injection signal on low pressurizer pressure. When the accident occurs, some of the reactor coolant blows down into the affected steam generator causing the level to rise. If the level rises sufficiently, a high level alarm will occur and the feedwater regulating valve will close. After the ruptured steam generator is identified, the planned procedure

The factor of four is not an actual stress concentration factor such as is described in Article 4, Design, of Section III, but is a margin of conservatism based on the Fracture Analysis Diagram in ASTM E-208 as well as the stress limits maintained by the prescribed operating procedures which rely upon administrative pressure and temperature control during heatup and cooldown (6). At the DTT, the stress is 20 percent of the yield strength versus a prescribed upper limit of 80 percent of the yield strength; therefore, at this point there is a margin of four (80/20).

Since the Fracture Analysis Diagram is based on a plot of nominal stress versus temperature and different size flaws (cracks) are assumed, the use of actual stress concentration factors does not apply.

As part of the plant operator training program, supervisory and operating personnel were instructed in reactor vessel design, fabrication, and testing, as well as precautions necessary for pressure testing and operating modes. The need for record keeping was stressed; such records being helpful for future summation of time at power level and temperature which tends to influence the irradiated properties of the material in the core region. These items are incorporated into the operating instructions.

Piping

The analysis of the Reactor Coolant Loop/Supports System is described in Section 3.9.

Steam Generators

Calculations confirm that the steam generator tube sheet will withstand the loading (which is quasi-static rather than a shock loading) caused by loss of reactor coolant. The maximum primary membrane plus primary bending stress in the tube sheet under these conditions is 23,853 psi for the Unit 2 steam generator. This is well below ASME Section III

yield strength of 41,112 psi at 660°F. Because the pressure in the primary channel head would drop to zero under the condition postulated, no damage will result to the channel head.

The rupture of primary or secondary piping was assumed to impose a maximum pressure differential of 2485 psi across the tubes and tube sheet from the primary side or a maximum pressure differential of 1100 psi across the tubes and tube sheet from the secondary side, respectively. Under these conditions there is no rupture of the primary to secondary boundary, including tubes and tube sheet. This criterion prevents any violation of the containment boundary.

To meet this criterion, it was established that under the postulated accident conditions, where a primary to secondary side differential pressure of 2,250 psia exists, the primary membrane stresses in the tube sheet ligaments, averaged across the ligament and through the tube sheet thickness, do not exceed 90 percent of the material yield stress at the operating temperature.

A complete tube sheet analysis was performed to verify the structural integrity of the primary-secondary boundary under blowdown plus seismic conditions.

Also, the primary membrane plus primary bending stress in the tube sheet ligaments, averaged across the ligament width at the tube sheet surface location giving maximum stress, do not exceed 135 percent of the material yield stress at the operating temperature. This criterion is felt to be applicable to abnormal operating circumstances in that it is consistent with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Paragraph N-712 for hydrotest criteria. The stresses and stress factors in the actual Unit 2 design tube sheet, obtained by using the above stress criteria, are given in Table 5.2-16.

The ratio of the allowable stresses on various components (based on an allowable membrane stress of 0.9 of the nominal yield stress of the material) to the computed stresses for a primary to secondary pressure differential of 2485 psi are summarized for the Unit 2 steam generators in Table 5.2-17.

Evaluation of the steam generator tube sheets was performed according to rules of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Article 4 - Design. The design criteria considered, encompassed consideration of both steady state, transient and emergency operations specified in the Equipment Specification. Due to the complex nature of the tube-tube sheet-shell-head structure, the analysis of the tube sheet required the application of results of related research programs (such as the design data on perforated plates resulting from PVRC programs) and the utilization of current techniques in computer analysis, the application of which was verified by comparison of analytical and experimental results for related equipment.

Examination of the introductory paragraph I-900 of the ASME Boiler and Pressure Vessel Code, Section III - Nuclear Vessels, reveals that consideration may be given to the stiffening effect of tubes in perforations, the staying action of the tubes if applicable, and the effect of stiffening on the plate stress levels, etc. Furthermore, it is noted that the stress analysis methods in Appendix I of Section III are described as accepted techniques for obtaining solutions to problems for which these procedures are applicable. It allows and requires use of other valid analytical or experimental techniques where necessary.

Although the Nuclear Pressure Vessel Code Article I-9 provides for rules and techniques in analysis of perforated plates, it is noted that the stress intensity levels for perforated plates are given for triangular perforation arrays. Westinghouse tube sheets contain square hole arrays. Hence, Westinghouse utilizes its own

data and that obtained from PVRC research in square array perforation patterns for development of similar charts for stress intensity factors and elastic constants. The resulting stress intensity levels and fatigue stress ranges are evaluated according to the stress limitation of the Code.

The Westinghouse analysis of the steam generator tube sheets was included as part of the Stress Report requirement for Class A nuclear pressure vessels. The evaluation was based on the stress and fatigue limitations outlined in Article 4, Design, of Section III. The stress analysis techniques utilized included all factors considered appropriate to conservative determination of the stress levels utilized in evaluation of the tube sheet complex. The analysis of the tube sheet complex included the effect of all appurtenances attached to the perforated region of the tube sheet considered appropriate to conservative analysis of stress for evaluation on the basis of Section III stress limitations. The evaluation involved the heat conduction and stress analysis of the tube sheet, channel head, secondary shell structure for particular steady design conditions for which Code stress limitations were to be satisfied and for discrete points during transient operation for which the temperature/pressure conditions must be known to evaluate stress maxima-minima for fatigue life usage. In addition, limit analyses were performed to determine tube sheet capability to sustain emergency operating conditions for which elastic analysis does not suffice. The analytic techniques utilized were computerized and significant stress problems were verified experimentally to justify the techniques where possible.

Generally, the analytic treatment of the tube-tube sheet complex included determination of elastic equivalent plate stress within the perforated region from an interaction analysis utilizing effective elastic constants appropriate to the nature of the perforation array. For the perforated region of the tube sheet, the flexural rigidity was based on studies of behavior of plates

In all cases evaluated, the steam generator tube sheet complex met the stress limitations and fatigue criteria specified in Article 4 of the Code as well as emergency condition limitations specified in the Equipment Specifications.

In this way, the tube-tube sheet integrity was demonstrated under the most adverse conditions resulting from a major breach in either the primary or secondary system piping.

Tabulations of significant results of the Unit 2 tube sheet complex are in Tables 5.2-18 through 5.2-25 and on Figures 5.2-7 through 5.2-9. Figure 5.2-10 denotes the Unit 2 primary-secondary boundary components shell locations.

Tabulations of significant results of the Unit 1 tube sheet complex are in Table 5.2-33. Table 5.2-34 presents significant results from the Unit 1 secondary shell and transition cone analysis. Stress results from the tube analysis are tabulated in Tables 5.2-35 and 5.2-36. Figures 5.2-22, 5.2-23 and 5.2-24 denote important stress locations.

Pressurizer

The pressurizer was analyzed for fatigue conditions in accordance with Section III of the ASME Boiler and Pressure Vessel Code using the thermal and pressure transient conditions listed elsewhere in this Section.

The pressurizer vessel was analyzed for the following loading conditions:

1. Normal operation loadings which included:

   a. Weight of water based on the vessel filled with cold water, and including insulation

   b. Normal loadings exerted by connecting piping

2. Seismic loadings which included:

   a. For the OBE, the pressurizer vessel is designed to resist earthquake loadings simultaneously in the horizontal and vertical directions and to transmit

such loadings through the vessel supports to the foundation. The OBE results in mechanical loadings and their combination with the normal operational loads is to be considered an upset condition. The components of loadings exerted by the external piping due to the OBE were included in this evaluation.

b. For the DBE, pressurizer vessel function is not impaired so as to prevent a safe and orderly shutdown of the reactor plant when the DBE loadings both horizontal and vertical acting simultaneously are imposed on the vessel. These loadings and the centers of gravity involved were determined on the basis of the vessel at normal operating pressure, temperature, and water level.

The DBE was considered a faulted condition with the following exceptions:

(1) The combination of all primary stress intensities in the vessel support skirt was required to be within the support skirt material yield strength specified in Section III of the ASME Boiler and Pressure Vessel Code.

(2) The stress intensity limits of the vessel associated with the DBE in combination with normal operation were as follows:

Pm $\leq$ 1.2 Sm or tabulated yield (Sy) whichever is greater Pl + Pb $\leq$ 1.8 Sm or 1.5 Sy whichever is greater

and safety valves connected to the top head of the pressurizer. The relief and safety valves discharge into the pressurizer relief tank which condenses and collects the valve effluent. The safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10 percent, in accordance with Section III of the ASME Boiler and Pressure Vessel Code. Their capacity is determined from considerations of the RPS and accident or transient conditions which may potentially cause overpressure.

The combined capacity of the safety valves is equal to or greater than the maximum surge rate resulting from complete loss of load without a direct reactor trip or any other control, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve setting. Safety and relief valve design parameters are shown in Table 5.2-8.

5.2.2.2 Report on Overpressure Protection

The "Report on Overpressure Protection" is not a part of the Code requirement for the Salem Station. Applicable codes for this station are listed in Tables 5.2-9A and 5.2-9B.

However, the overpressure protection capability of Westinghouse PWRs, including Salem Station, is discussed in Reference 15.

5.2.2.3 RCS Pressure Control During Low Temperature Operation

Refer to Section 7 for a discussion of the Overpressure Protection System for low temperature operation.

5.2.3 General Material Considerations

Table 5.2-26 summarizes the quality assurance program with regard to inspections performed on RCS components. In addition to the inspections shown in Table 5.2-26, there were those which the equipment supplier performed to confirm the adequacy of material received and those performed by the material manufacturer in producing the basic material. The inspections of reactor vessel, pressurizer, and steam generator were governed by ASME Code requirements. The inspection procedures and acceptance standards required on pipe materials and piping fabrication were governed by USAS B31.1 and Westinghouse requirements and are equivalent to those performed on ASME coded vessels.

Procedures for performing the examinations were consistent with those established in the ASME Code Section III and were reviewed by qualified engineers. These procedures have been developed to provide the highest assurance of quality material and fabrication. They consider not only the size of the flaws, but equally as important, how the material was fabricated, the orientation and type of possible flaws, and the areas of most severe service conditions. In addition, the accessible external surfaces of the primary RCS pressure containing segments receive a 100-percent surface inspection by magnetic particle or liquid penetrant testing after hydrostatic test. All reactor vessel plate material was subjected to angle beam gas well as straight beam ultrasonic testing to give maximum assurance of quality. All reactor vessel forgings received the same inspection. In addition, 100 percent of the material volume was covered in these tests as an added assurance over the grid basis required in the Code.

Quality control engineers monitored the supplier's work, witnessing key inspections not only in the supplier's shop but in the shops of subvendors of the major forgings and plate material. Normal surveillance included verification of records of material, physical and chemical properties, review of radiographs,

the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated ~~wall~~ exposure will be made by use of data on all capsules withdrawn.

The surveillance program for Unit 1 was prepared to meet ASTM E-185-70, Section 3.3. The test materials were procured and machined in 1969 prior to publication of ASTM E-185-70 and prior to issuance of "Reactor Vessel Material Surveillance Program Requirements," 10CFR50, Appendix H. Therefore, the eight capsules to be provided do not include five capsules which contain specimens from base metal, weld metal, and heat affected zone metal as required in 10CFR50, Appendix H.

For Unit 2, the surveillance program has been revised to meet proposed ASTM and NRC requirements reflecting ASME Code Case 1514 and will include eight capsules, each of which will contain the most limiting base plate, weld metal, and heat affected zone material.

The tentative schedule for capsule removal outlined hereunder is based on the ASTM E-185 removal requirement and the projected fluence based on the current low leakage fuel design.

The tentative schedule for Unit 1 capsule removal is as follows:

Capsule T	Removed in 1979
Capsule Y	Removed in 1984
Capsule Z	Removed in 1987
Capsule S	At 12 EFPY
Capsule V	At 32 EFPY
Capsule U	Standby
Capsule X	Standby
Capsule W	Standby

The tentative schedule for Unit 2 capsule removal is as follows:

Capsule T	Removed in 1983
Capsule U	Removed in 1986
Capsule X	At 6 EFPY
Capsule Y	At 17 EFPY
Capsule S	At 32 EFPY
Capsule V	Standby
Capsule W	Standby
Capsule Z	Standby

5.2.4.4.2 Material Properties of Salem 1 and 2 Reactor Pressure Vessels

A good set of RPV material data is very important in accurately assessing the RT_{pts}. The chemical and mechanical properties of the Salem weld data, used in this study, were the result of a thorough investigation performed by Combustion Engineering. The RPV plate data in the beltline region were obtained from Westinghouse documents.

Figure 5.2-18 shows the assembly of the Salem Reactor Pressure Vessel. The Salem vessels were fabricated by Combustion Engineering. The Reactor Vessel beltline materials that directly surround the effective height of the core and the adjacent region that are predicted to experience sufficient neutron irradiation damage consist of the intermediate and lower shell course and their associated welds. Figures 5.2-19 and 5.2-20 identify and schematically locate the Reactor Vessel plates and welds in the beltline region for Salem Units 1 and 2, respectively. Figure 5.2-21 shows the locations of surveillance capsules.

The chemical and mechanical properties of the beltline region welds and plates of Salem Units 1 and 2 which are necessary to calculate the fracture toughness of the vessel are tabulated in Tables 5.2-30, 5.2-31 and 5.2-32. The fracture toughness state of the vessel is characterized by the quantity RT_{pts} (Reference Temperature for Pressurized Thermal Shock). The RT_{pts} equations specified in the PTS final rule are used. The equations are:

5.3 THERMAL HYDRAULIC SYSTEM DESIGN

5.3.1 Analytical Methods and Data

The thermal and hydraulic design bases of the Reactor Coolant System (RCS) are described in Section 4.

5.3.2 Operating Restrictions on Pumps

The minimum net position suction head (NPSH) and minimum seal injection flow rate must be established before operating the reactor coolant pumps. Requirements are set forth in the pump operating instructions.

5.3.3 Temperature Power Operating Map

Reactor power is controlled to maintain average coolant temperature at a value which is a linear function of load.

5.3.4 Load Following Characteristics

Load following is discussed in Section 5.2.1.5.2.

5.3.5 Transient Effects

Transient effects on the RCS are evaluated in Section 15.

5.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal and hydraulic characteristics are given in Tables 4.3-1, 4.4-1, and 4.4-2.

5.3.7 Natural Circulation Capability

The capability to perform natural circulation cooldown has been analyzed following a transient in a Pressurized Water Reactor of different design in which significant void formation occurred in

the reactor vessel head. The analysis took into account such factors as the amount of bypass flow to the upper head region, RCS cooldown/depressurization rate, heat removal via the Control Rod Drive Mechanism (CRDM) cooling fans and ambient losses. Salem is a "T-Hot" plant, i.e., one in which the upper head water temperature is assumed equal to the hot leg temperature. Analysis results are summarized below.

The average cooldown rate of the upper head fluid due to the 25°F per hour natural circulation cooldown rate is about 10°F per hour. The total upper head cooldown rate due to both the natural circulation cooldown and the CRDM fans varies from 31°F per hour initially to around 21°F per hour when the upper head temperature is cooled to 350°F. Thus, with the CRDM fans operating during the cooldown with no void formation occurring in the upper head area, the operator is required to maintain a minimum of 50°F subcooling during the depressurization.

A Salem-specific analysis has been performed to determine the natural circulation cooldown strategy to prevent void formation without CRDM fans in operation. Without the CRDM fans in operation, the plant can be cooled down to Residual Heat Removal (RHR) System conditions at a natural circulation cooldown rate of 25°F per hour with no void formation occurring in the upper head with appropriate precautions being taken by the operators. The operator is required to maintain a minimum of 50°F subcooling until the primary system pressure reaches 50 psi below the permissive to block SI. After the automatic safety injection signals are blocked, the operator establishes 200°F subcooling (approximately 430°F in the hot leg) and maintains at least 200°F subcooling (or the Technical Specification limit if it is more restrictive) to a primary system pressure of 1200 psig. Depressurization is stopped at 1200 psig and the cooldown is continued until the primary system temperature is less than 350°F. At this point, the operator is required to wait for approximately 8 hours to allow the upper head to cool off, corresponding to a saturation temperature less than the RHR cut-in pressure (325 psig). Finally, the primary system is depressurized to 325 psig and the RHR System used for further cooldown.

Unit 1 has Model-F steam generators which are similar in design to the Series 51 in natural circulation capabilities. Hence, the general conclusions drawn above are also applicable to Unit 1 with the Model-F steam generators.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable plant experience with the anti-reverse rotation device has shown high reliability of operation.

5.5.1.3.11 Shaft Seal Leakage

Leakage along the RCP shaft is controlled by three shaft seals arranged in series. Charging flow is directed to each RCP via a seal water injection filter. It enters the pump and is directed to a point between the pump shaft bearing and the pump seals. The flow splits and a portion flows down the shaft through and around the lower radial bearing, down past the thermal barrier heat exchanger and into the RCS; the remainder flows up the pump shaft annulus and provides a back pressure on the Number 1 seal and a controlled flow through the seal. Above the seal, most of the flow leaves the pump via the Number 1 seal leak-off line. Minor flow passes through the Number 2 seal and its leak-off line, and through the Number 3 seal and its leak-off line.

5.5.1.3.12 Seal Discharge Piping

Discharge pressure from the Number 1 seal is reduced to that of the volume control tank. Water from each pump's Number 1 seal is piped to a common manifold, through the seal water return filter and through the seal water heat exchanger, where the temperature is reduced to that of the volume control tank. The Number 2 and Number 3 leak-off line dump Number 2 and Number 3 seal leakage to the reactor coolant drain tank.

5.5.1.3.13 Loss of Offsite AC Power

During normal operation, seal injection flow from the Chemical and Volume Control System (CVCS) is provided to cool the RCP seals and the Component Cooling Water System provides flow to the thermal

barrier heat exchanger to limit the heat transfer from the reactor coolant to the RCP internals. In the event of loss of offsite power, the RCP is deenergized and both of these cooling supplies are terminated; however, the diesel-generators are automatically started and either seal injection flow or component cooling water to the thermal barrier heat exchanger is automatically restored within seconds. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to loss of seal cooling during a loss of offsite power to at least 2 hours.

5.5.1.3.14 Loss of Component Cooling Water

Loss of component cooling water and its effects on the RCP are discussed in Section 9.2.

5.5.1.4 Test and Inspections

Pressure boundary parts of the RCPs can be inspected in accordance with the ASME Code for "Inservice Inspection of Nuclear Reactor Coolant Systems," Section XI.

The pump casing is cast in two pieces, and joined by electroslag welding. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The RCP quality assurance program is given in Table 5.2-26.

5.5.2 Steam Generators

5.5.2.1 Design Bases

Steam generator design data are given in Table 5.2-5 for Unit 2 and Table 5.2-5a for Unit 1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Section 11. Rupture of a steam generator tube is discussed in Section 15.

The internal moisture separation equipment is designed to assure that moisture carryover does not exceed 0.25 percent by weight under the following conditions:

1. Steady-state operation up to 105 percent of full-load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full-power steam flow per minute in the range from 15 percent to 105 percent of full-load steam flow.

3. A step load change of 10 percent of full power in the range from 15 percent to 105 percent full-load steam flow.

The steam generator tube sheet complex meets the stress, limitations and fatigue criteria specified. Code and materials' requirements of the steam generator are given in Tables 5.2-9 and 5.2-27.

The steam generator design maximizes integrity against hydrodynamic excitation and vibration failure of the tubes for plant life.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces.

5.5.2.2 Design Description

The Unit 2 steam generator shown on Figure 5.1-3 (for Salem Unit 2) is a Series 51, vertical shell and U-tube evaporator with integral moisture separating equipment. The Model-F steam generator for Unit 1 is shown in Figure 5.1-3a. The Model-F is very similar to the Series 51 generator except in tube dimensions, number of tubes and separators. A specific description of the Model-F steam generator is given in Section 5.5.2.2.2.

5.5.2.2.1 Unit 2 Series 51 Steam Generators

The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet. Manways are provided for access to both sides of the divided head. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The unit is primarily carbon steel. The heat transfer tubes and the divider plate are Inconel and the

interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel.

Feedwater flows directly into the annulus formed by the shell and tube bundle wrapper before entering the boiler section of the steam generator. Subsequently, water-steam mixture flows upward through the tube bundle and into the steam drum section. A set of centrifugal moisture separators, located above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.75 percent (0.25 percent moisture). The moisture separators recirculate flow mixes with feedwater as it passes through the annulus formed by the shell and tube bundle wrapper.

The steam drum has two bolted and gasketed access openings for inspection and maintenance of the dryers, which can be disassembled and removed through the opening.

5.5.2.2.2 Unit 1 Model-F Steam Generators

The Model-F steam generators are vertical U-tube steam generators that were designed and fabricated in accordance with the ASME Code, 1971 Edition, Summer 1973 Addenda, Class 1, Division 1 for use in a closed cycle pressurizer water reactor system. Unit 1 has Model-F steam generators.

The tube bundle of the Model-F steam generator consists of 5626 thermally-treated U-tubes fabricated from ASME SB-163 (Inconel). The O. D. of each tube is 0.688 inches with a nominal tube wall thickness of 0.040 inches. The ends of the tubes are expanded the full depth of the tube plate, and the tubes are welded to the Inconel cladding on the primary face of the tube plate. Overall height of the Model-F steam generator tube bundle extends approximately 348 inches above the secondary face of the tube plate.

The Model-F steam generators utilize two-stage moisture separators to remove moisture from the wet steam produced by the tube bundle to deliver dry steam to the turbine generator. The first stage separator assembly is located directly above the tube bundle. It is approximately 10 feet high and contains sixteen 20 inch diameter swirl vane assemblies. Steam at the exit end of the first stage separators still contains some entrained moisture and is passed through the second stage separators, containing banks of contoured vanes designed to

remove water from steam. The moisture separator housing consists of two four-sided tiers, one above the other, providing the frames in which the banks of vanes are installed.

The steam outlet nozzle has an I. D. of 29 inches and is located at the apex of the upper elliptical head. The steam outlet nozzle contains a flow limiting device which operates on the venturi principle, to choke flow in the event of a steam line break.

Model-F steam generators are equipped with a blowdown nozzle (2 in. dia.) and a drain nozzle (2 in. dia.). Liquid level connections provide openings for narrow and wide range water level instrumentation used for feedwater control and reactor protection systems. Wide range taps provide a range of 560 inches and narrow range taps provide a range of 128 inches for liquid level measurement. A sampling nozzle (2 inch nominal) is provided in Model-F steam generators used in Unit 1.

5.5.2.3 Design Evaluation

5.5.2.3.1 Natural Circulation Flow

The steam generators (which provide a heat sink) are at a higher elevation than the reactor core (which is the heat source). Thus, natural circulation is assured for the removal of decay heat.

5.5.2.3.2 Secondary System Fluid Flow Instability Prevention

In order to prevent the occurrence of water hammer, which has been experienced at other plants, the feedwater distribution ring headers have been modified in Unit 2. The flow from the headers takes place through the top of the headers, rather than out the bottom as originally designed. This modification has been demonstrated to preclude water hammer as discussed in detail in Section 10.4. The Model-F steam generators in Unit 1 were originally fabricated with this feature to preclude water hammer.

The limiting case for heat transfer capability is the "Nominal 100 Percent Design" case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case, and includes a conservative allowance for tube fouling. Adequate tube area is selected to assure that the full design heat removal rate is achieved. The best estimate for the heat transfer coefficient is 1301 Btu/hr-ft^2-°F, which is approximately

5 to 10 percent less than the heat transfer performance experienced at a number of operating plants. The coeffi~~cie~~ent incorporates a specified fouling factor resistance of 0.00005 hr-ft^2-°F/Btu, which is the value selected to account for the differences in the measured and calculated heat transfer performance as well as provide the margin indicated above. Although margin for tube fouling is available, operating experience to data has not indicated that steam generator performance decreases over a long-term period.

5.5.2.3.3 Tube and Tube Sheet Stress Analyses

Tube and tube sheet stress analyses of the steam generator are given in Section 5.2. Calculations confirm that the steam generator tube sheet will withstand the loading (which is quasi-static rather than a shock loading) caused by loss of reactor coolant.

5.5.2.3.4 Flow-Induced Vibration

In the design of the steam generators, consideration has been given to the possibility of vibratory failure of tubes due to mechanical or flow-induced excitation. This consideration includes detailed analysis of the tube supporting system as well as an extensive research program with tube vibration model tests. The major cause of tube vibratory failure in heat exchanger components is that due to hydrodynamic excitation by the fluid outside the tube. Consideration is given to three regions where the possibility of flow-induced vibration may exist:

1. At the entrance of downcomer feed to the tube bundle (cross low)
2. Along the straight sections of the tube (parallel flow)
3. In the curved tube section of the U-bend (cross flow)

From the description of these regions, it is noted that two types of flow exist, namely, cross flow and parallel flow. For the case of parallel flow, analysis is done to determine the vibratory deflections. Analysis of the steam generator tubes indicates the flow velocities to be sufficiently below that required for damaging fatigue or impacting vibratory amplitudes. The support system, therefore, is deemed adequate to preclude parallel flow excitation. For the case of flow excitation, it is noted in the literature that several techniques for the analysis of the tube vibration exist. The design problem is

to ascertain that the tube natural frequency is well above the vortex shedding frequency. In order to avoid resonant vibration, adequate tube supports are provided.

Since the problem of cross flow-induced vibration was of major concern in the design of shell and tube heat exchangers, consideration was given to the experimental evaluation of the behavior of tube arrays under cross flow. While consideration was given to instrumentation of actual units in service, the hostile environment would limit the amount and quality of information obtained therefrom. As a result, it was deemed prudent to undertake a research program which would allow the study of fluid elastic vibratory behavior of tubes in arrays. A wind tunnel was built specifically for this purpose. The research facilities for the tube vibration study have since been expanded with the construction of a water tunnel facility.

The results of this research confirm the vortex shedding mechanism. More significant, however, is the evaluation of a fluid elastic mechanism not associated with vortex shedding. This phenomenon is not commonly understood and could be a source of vibration failure. Steam generators are evaluated on this basis in addition to the aforementioned techniques and found adequately designed. Testing has also been conducted using specific parameters of the steam generator and the results show the support system to be adequate.

Summarizing the results of analysis and tests of steam generator tubes for flow-induced vibration, it can be stated that a check of support adequacy has been made using all published techniques believed appropriate to heat exchanger tube support design. In addition, the Tube Support System is consistent with accepted standards of heat exchanger design utilized throughout the industry (spacing, clearance, etc.). Furthermore, the design techniques are supplemented with a continuing research and development program to understand the complex mechanism of concern.

Service experience of steam generators shows that flow-induced vibration and cavitation effects do not cause tube thinning. Preliminary estimates of tube degradation from erosion/corrosion

mechanisms indicate that approximately 2 1/2 mils wall thinning (2 mils primary, 1/2 mil secondary side) will result over the 40-year lifetime.

The effects of vibration, erosion, and cavitation have been given consideration and the stress limitations for each category have been met. Analysis of loss-of-coolant accident (LOCA) blowdown forces on as-fabricated U-tubes has shown that the maximum bending load elastic stress intensity is well below the faulted condition limit. The maximum bending load elastic stress intensity (based on the minimum tube wall thickness) would increase only within the range of 5 to 10 percent and would still be below the faulted condition limit. Therefore, as a minimum, at least 2 1/2 mils (per wall) thinning can be tolerated without exceeding the allowable stress limits. Vibration effects are eliminated during normal operation by the supporting system. Under LOCA conditions, vibration is of a short duration and there is no endurance problem.

Further consideration is given to the possibility of mechanically excited vibration, in which resonance of external forces with tube natural frequencies must be avoided. It is believed that the transmissibility of external forces either through the structure or from fluid within the tubes is negligible and should cause little concern.

Finally, it should be noted that successful operational experience with several steam generator designs has given confidence in the overall approach to the tube support design problem.

Tests and Inspections

The steam generator quality assurance program is given in Table 5.2-26.

Radiographic inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tube sheet cladding, channel head cladding, tube-to-tube sheet weldments, and weld deposit cladding.

Liquid penetrant inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tube sheet forging, channel head casting, nozzle forgings, and the following weldments:

1. Nozzle to shell

2. Support brackets

3. Instrument connections (primary and secondary)
   (Note: Unit 1 steam generators have no primary instrumentation connections)

4. Temporary attachments after removal

5. All accessible pressure containing welds after hydrostatic test.

Magnetic particle inspection and acceptance standards are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tube sheet forging, tube sheet cladding, secondary shell and heat plate and nozzle forgings.

The heat transfer tubing is subjected to eddy current test.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes are subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure

multiplied by the ratio of the material allowable stress at the testing temperature.

Manways are provided for access to both the primary and secondary sides.

Steam generator tube inspection will be performed in accordance with Technical Specifications. Due to activity in the channel head and the large number of tubes involved, tube testing is done on a per-plant basis. The extent of tube testing planned in any particular plant will depend on tube performance to date, the channel head activity, and the results of tube sample testing. An eddy current testing method is available if the tubes should require inspection.

5.5.3 Reactor Coolant Piping

5.5.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and assure compatibility with the operating environment.

RCS pressure boundary piping codes for both units are stated in Table 5.2-9.

5.5.3.2 Design Description

Principal design data for the reactor coolant piping for both units are given in Table 5.2-7.

9. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.

10. Resistance temperature detector scoop element, pressurizer spray scoop, sample connection with scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

11. All branch connection nozzles attached to reactor coolant loops.

12. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power-operated pressurizer relief valves and pressurizer safety valves.

13. Seal injection water and labyrinth differential pressure lines to or from the RCP inside reactor containment.

14. Auxiliary spray line from the isolation valve to the pressurizer spray line header.

15. Sample lines from pressurizer to the isolation valve.

Details of the materials of construction of reactor coolant piping and fittings are listed in Table 5.2-26.

5.5.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown, and seismic loads is discussed in Section 5.2.

5.5.3.4 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

An upper limit of about 50 feet per second is specified for internal coolant velocity to avoid the possibility of accelerated erosion. All pressure containing welds out to the second valve that delineates the reactor coolant pressure boundary are available for examination with removable insulation.

5.5.3.5 Tests and Inspections

Inservice inspection is discussed in Section 5.2.8. The RCS piping quality assurance program is given in Table 5.2-26.

A description of the quality assurance inspections of these components is contained in Section 5.2.3.5.

5.5.4 Main Steam Line Flow Restrictors

Each steam line is provided with a flow restrictor to limit the blowdown rate of steam from the steam generators in the event of a main steam line rupture. The flow restrictors are described in detail in Section 10.3.

In addition to the main steam line flow restrictors in Unit 1, the Model-F steam generators have flow restrictors in the steam outlet nozzle. The area of this flow restrictor integral to the Model-F generator is 1.4 ft^2.

5.5.5 Main Steam Line Isolation System

Main steam isolation valves are described in Section 10.3.

5.5.6 Reactor Core Isolation Cooling System

This section is not applicable to PWRs.

5.5.7 Residual Heat Removal System

5.5.7.1 Design Bases

The RHR System is designed to remove residual and sensible heat from the core and reduce the temperature of RCS during the second phase of plant cooldown. During the first phase of cooldown, the

located inside the containment are also piped to the relief tank. The tank normally contains water and a predominantly nitrogen atmosphere; however, provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen or oxygen.

By means of its connection to the Waste Processing System, the PRT provides a means for removing any noncondensable gases from the RCS that might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This arrangement provides for condensing and cooling the steam by mixing it with water that is near ambient temperature. A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe.

The PRT has pressure, temperature, and level indications and alarms in the control room.

5.5.11.3 Design Evaluation

The volume of water in the tank is capable of absorbing heat from the assumed discharge, assuming an initial temperature of 120°F and increasing to a final temperature of 200°F. If the temperature in the tank rises above 120°F during plant operation, the tank is cooled by spraying in cool water and draining out the warm mixture to the Waste Disposal System.

The spray rate is designed to cool the tank from 200°F to 120°F in approximately 1 hour following the design discharge of pressurizer steam. The volume of nitrogen gas in the tank is selected to limit the maximum pressure following a design discharge to 50 psig.

The rupture discs on the PRT have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure and the maximum rupture disc

burst point are twice the calculated pressure resulting from the maximum design safety valve discharge described above. The tank and rupture disc holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

The PRT rupture disc is the vent path for both the reactor vessel head and the pressurizer vent. The annulus area containing the PRT is well ventilated. With three out of five fan coil units running at reduced speed during an accident condition, the annulus area containing the PRT is adequately ventilated with an air change every hour. A review of possible sources of ignition in the immediate vicinity of interest indicates no concern. Venting through the PRT rupture disc will not adversely affect any system or component essential for safe shutdown.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent back-pressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

5.5.12 Valves

Valves in contact with the reactor coolant are primarily constructed of stainless steel. For certain applications, such as hard surfacing and packing, design and functional considerations dictate the use of materials other than stainless steel.

All manual and motor-operated valves of the RCS that are 3 inches and larger, (except as listed below), are provided with double-packed packing boxes and intermediate lantern ring leakoff connections. All throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. Leakage to the atmosphere is essentially zero for these valves. RCS valve codes, materials, and quality assurance measures are summarized in Tables 5.2-9, 5.2-27 and 5.2-26, respectively.

The valves listed below have a single set packing configuration and inactive leakoff lines.

Salem #1			Salem #2		
1PS1	1PS25	1PR6	2PS1	2PS25	2PR6
1PS3	1PS28	1PR7	2PS3	2PS28	2PR7
1PS24	1PS29		2PS24	2PS29	

5.5.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code, Section III. Safety valve position is monitored by limit switches which alarm in the Control Room when any valve is not in the fully closed position.

The pressurizer PORVs prevent actuation of the reactor high pressure trip for all design transients up to and including the design step load decreases with steam dump. The relief valves also limit opening of the spring-loaded safety valves. The opening of any pressurizer PORV is annunciated in the control room.

The Salem PORVs, PORV block valves and associated downstream piping have been evaluated for operation under water-solid conditions, and have been found to be adequate. The PORVs can be relied upon to prevent challenges to the pressurizer safety valves when the pressurizer is water-solid. Administrative controls (procedures) are placed upon the PORV block valves to prevent their closure when the pressurizer is water-solid.

Westinghouse has completed a generic study (2) of PORV reliability and concluded that PORVs are adequately reliable so as not to require automatic block valve closure. Public Service Electric & Gas (PSE&G) has determined that the information provided in the generic report is applicable to the Salem Generating Station. Accordingly, automatic isolation of the PORVs is not provided.

5.5.14 Reactor Coolant System Component Supports

5.5.14.1 Description

Reactor vessel supports are assemblages of plates built up to seat the reactor vessel nozzle shoes. There are four shoe supports for each reactor vessel. The support assemblages are air cooled by negative pressure ducts that draw the air away from the space surrounding the vessel through vent holes drilled in the multiple plates. For support details, see Figure 5.5-3.

The steam generator supports are shown on Figure 5.5-4. The weight of the steam generator is transferred through four steel columns at its base to the supporting frame. The steam generator penetrates the operating floor of the Containment Building. The

elevation of the operating floor is approximately at the center of gravity of the steam generator. It is supported at the floor by two sets of snubbers and bumper blocks which resist the horizontal forces and overturning moments generated from pipe rupture or earthquake motion. The supporting frame has its upper bay braced in both directions. The lower bay consists of two parallel planar trusses which are pin-hinged at the top and bottom to allow for thermal displacement. The horizontal forces at the base of the steam generator are transferred through combined truss and frame action to the lower bay of the support structure. The primary loop piping provides lateral support for the frame in the direction normal to the plane of the trusses. Lateral restraint for blowdown is provided at the top of the support structure by two struts connected to the reactor shield wall. The struts are in two bolted sections with gaps for free thermal travel and adjustment.

The RCP supports as shown on Figure 5.5-5 also consist of an upper and lower section. The upper section is a welded steel assembly and is constructed to accommodate the bolts of the feet of the RCP. The lower section is composed of two parallel planar trusses, pin-hinged at the top and bottom to provide for thermal expansion. Lateral support in the direction normal to the plane of the trusses is provided by the primary loop piping. Blowdown restraint is provided at the top of the supporting structure by struts connected to the shield wall. The struts are in bolted sections with gaps for free thermal travel and adjustment.

The steam generator and RCP supports are anchored to the containment base slab by heavy welded steel frames embedded in the concrete and tied to the base mat by 6 and 4 inch diameter bolts, 18.5 feet long. Typical details for the embedded steel for equipment supports are shown on Figure 5.5-6.

All the statements above are applicable to both the Series 51 and the Model-F steam generators, except that the lower support design was modified to accommodate the Model-F steam generator. The Series 51 generator was supported from lugs on the channel head while the Model-F generator is supported from the tube sheet elevation so the existing columns had to be replaced by longer ones. The lower support design for the Unit 1 Model-F generators is shown in Figures 5.5-4b through 5.5-4f.

The pressurizer also penetrates the operating floor of the reactor containment. Stop lugs are embedded in the floor slab to provide the lateral support for the pressurizer at its mid-height. The

vessel skirt is bolted to a steel plate which is in turn welded to the top of the support structure. The support structure frame is braced in both directions. It is further constrained against lateral movement at its top by four short wide flange struts, two in each perpendicular direction, connected to the polar crane support wall. For pressurizer support details, see Figure 5.5-7.

5.5.14.2 Fabrication

For original fabrication, all shop welding was done in accordance with AWS D2.0, "Specification for Welded Highway and Railway Bridges." Detailed joint procedure specifications were submitted by the fabricator for review and approval by PSE&G engineering personnel. The following preheat requirements were specified to minimize residual stress:

1. Material less than 3/4-inch thick shall be preheated to 100°F if the ambient temperature falls below 40°F.

2. Material 3/4 to 1 1/2-inches thick shall be preheated to 150°F prior to welding.

3. Material 1 1/2 to 2 1/2-inches thick shall be preheated to 225°F before welding.

4. Material over 2 1/2-inches thick shall be preheated to 300°F before welding.

Welding of steam generator support modifications for Unit 1 Steam Generator Replacement was done in accordance with AWS D.1.1, Structural Welding Code - Steel, 1996 Edition.

Most intersecting primary members are connected flange to flange by butt welds or are connected to gusset plates by fillet welds. These types of connections are not susceptible to lamellar tearing.

5.5.14.3 Evaluation

Analysis of the RCS supports is discussed in Section 3.9. Steam generator and RCP support load combinations and allowable stress

limits are given in Table 5.5-3. The average operating temperature of these supports is approximately 100°F, with a minimum of 70°F. Material for primary component support structures subject to high-intensity impact loads was required to pass a Charpy impact test of 20 foot-pounds at 20°F to verify its fracture toughness characteristics. This fracture toughness assures that brittle behavior will not be exhibited.

5.5.14.4 Inspection

All welds were subject to visual inspection in accordance with American Welding Society requirements. All full penetration shop welds were subject to magnetic particle inspection at four depths supplemented, where practical, by ultrasonic inspection of the finished weld. After original installation, welds on the supports were subject to another magnetic particle inspection. This inspection revealed only minor surface defects on some welds, none critical to the structural integrity of the supports. Nonetheless, these welds were repaired.

In Unit 1 with the Model-F steam generators, the design basis for the lower supports is PSE&G Detail Specification No. 69-7031. The partial penetration welds between the new support columns and the existing support structure were magnetic particle (MT) examined after the root pass and the final pass. The partial penetration welds for the side plates were magnetic particle (MT) examined after the final pass. For the one side plate with full penetration welds, required because of the column offset of 2.203", the welds were MT examined at four thicknesses (Root, 1/3T, 2/3T, and Final) during the process. The stiffener plates were installed using full penetration welds and were MT examined at four thicknesses (Root, 1/3T, 2/3T, and Final) during the process. All new welds were visually examined (VT3) in accordance with Section IWF-3410 of the ASME Code, Section XI, with Addenda through Summer 1983.

5.5.15 Partial RCS Loop Operation

During partial drain operations of the RCS, adequate RCS inventory, level control, and Net Positive Suction Head (NPSH) must be maintained. If it is required that the RCS water level be lowered to drain the steam generator tubes, the residual heat removal flow rate through each of the RHRS loops should be throttled back to prevent vortexing and possible air entrainment of the pumps. Draining is to the point where the indicated level is stable and predetermined point (usually at the elevation of the center of the reactor vessel nozzles). At this point, reactor coolant level is monitored continuously to assure that the RHRS inlet lines do not become uncovered.

Inventory makeup, if required, is accomplished via the CVCS centrifugal charging pumps.

Should a RHRS inlet line become uncovered, air may be drawn into the suction piping and entrained in the fluid. Factors which minimize the effects of air entrainment on pump performance are as follows:

1. The location of the residual heat removal pumps provides positive head on the pump inlet, and

2. The circulation flow rate is kept low and unnecessary circulation of fluid is avoided (i.e., minimum flow required for core decay heat removal and boron mixing is maintained).

Provisions have been made to minimize the effects of air entrainment. However, should such an event preclude the continued use of the operating train, actions need to be taken to permit the utilization of the alternate train by providing sufficient refill/makeup from the CVCS/charging pumps. Provisions are incorporated to ensure rapid restoration of the RHRS to service in the event that the RHRS pumps become air bound. On identifying this situation, the affected train would be isolated, the reason for the loss of RHR would be identified and corrected, and heat removal accomplished by the redundant train.

Procedures have been developed to address the provision of alternate sources of cooling should loss of RHR cooling occur during shutdown maintenance evolutions. These provisions consider maintenance evolutions during which more than one cooling system may be unavailable, such as loss of steam generators when the RCS has been partially drained for steam generator inspection or maintenance.

5.5.16 References for Section 5.5

1. Hill, R. A., et al., "Evaluation of Mispositioned ECCS Valves," WCAP-8966 (Proprietary) and WCAP-9207 (Nonproprietary), September 1977.

2. Westinghouse Electric Corp., "Probabilistic Analysis and Operational Data in Response to NUREG-0737, Item II.K.3.2, for Westinghouse NSSS Plants," WCAP-9804, February 1981.

3. ABB Combustion Engineering Report CEN-606, Revision 00, dated 5/21/93, Boric Acid Concentration Reduction Effort, Technical Basis and Operational Analysis for Salem Generating Station Units 1 and 2

not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap readout has been well established by the following equation:

$$\frac{\Delta P}{\Delta P_o} = \left(\frac{w}{w_o}\right)^2$$

where ΔP_o is the referenced pressure differential with the corresponding referenced flow rate ω_o and ΔP is the pressure differential with the corresponding referenced flow rate ω. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse pressurized water reactor (PWR) plants. The expected absolute accuracy of the channel is within ±10 percent and field results have shown the repeatability of the trip point to be within ± 1 percent. The analysis of the loss of flow transient presented in Section 14.1 assumed instrumentation error of ±3 percent.

The combined flow from the hot and cold leg RTD manifolds passes through an orifice before discharging back to the RCS at the suction side of the RCP. The flow is indicated locally by a d/p gage and by status lights in the control room. Low flow through either the hot or cold leg warns of possible inaccuracy in the corresponding temperature signals; therefore, an alarm is actuated.

5.6.7 Reactor Coolant Pump Motor Instrumentation

A dual purpose switch is provided on the high pressure oil lift system. Upon low oil pressure the switch actuates an alarm on the main control board. In addition, the switch is part of an interlock system that prevents starting of the pump until the oil

lift system is operating and oil pressure is established. A local pressure gage is also provided.

Level switches are provided in the motor radial bearings and thrust bearing oil reservoirs. The switches actuate high and low level alarms on the main control board.

Thermocouples are located in the upper and lower thrust bearing shoes. These elements provide signals for multi-point recorder on the main control board and actuate an alarm on high temperature.

A RCP trip criterion has been adopted which assures pump trip for all losses of primary coolant for which pump trip is considered necessary, but which also permits pump operation during most non-LOCA events, including steam generator tube rupture events up to the design basis double-ended tube rupture. The controlling parameter selected for pump trip actuation is RCS pressure. The RCS wide-range pressure instrumentation will be monitored.

5.6.8 Loose Parts Monitoring

A Loose Parts Monitoring (LPM) System supplied by Westinghouse Electric Corporation has been installed for each of the two units of Salem Generating Station. (This LPM System has been designated as the Metal Impact Monitoring System by Westinghouse). The LPM System has been designed to enable early detection of the presence of metallic debris, loose parts, or restrained loose parts, inside the Nuclear Steam Supply System (NSSS) during plant startup and commercial operation. Any form of metallic debris, loose parts, or restrained loose parts, when carried or agitated by the reactor coolant flow may attain sufficient velocities to impact and damage the interior of the NSSS pressure boundary.

The LPM system is realized by on-line processing, transmission, and conditioning of the signals from a group of strategically located Piezoelectric accelerometers (a total of 12) mounted externally to the wall of NSSS with proper indication and alarms.

a manner to avoid undue risk to the health and safety of the public.

During the recirculation phase the ECCS is tolerant of one active or one passive failure, but not in addition to a single failure in the injection phase. One active or passive failure in the systems required for long-term ECCS operation will not prevent the accomplishment of the ECCS objectives nor cause the total offsite dose to exceed 10CFR100 guidelines, with credit for detection and operator action.

In the particular case of an ECCS pump being out for maintenance, an additional active or passive failure is not considered. The maximum period that operation would be continued with one pump out for maintenance is specified in the Technical Specifications.

The extreme upper limit of public exposure is taken as the levels and time periods presently outlined in 10CFR100, i.e., 300 rem to the thyroid or 25 rem whole body in 2 hours at the exclusion radius, and 300 rem to the thyroid or 25 rem whole body over the duration of the accident at the low population zone distance. The accident condition considered is the hypothetical case of a release of fission products as in TID 14844. Also, the total loss of all outside power is assumed concurrently with this accident.

Under the above accident conditions, the Containment Spray and Fan Cooling Systems are designed and sized so that, operating with partial effectiveness, it can supply the necessary post-accident cooling capacity to assure the maintenance of containment integrity; that is, keep the pressure below design pressure at all times, assuming that the core residual heat is released to the containment as steam. Partial effectiveness is defined as operation of a system with at least one active component failure.

The fan cooling system's performance capability for defense against thermally induced overpressure, the development of two-phase flow regions, and column separation or voiding leading to the possibility of waterhammer events are analyzed for as part of the NRC's Generic Letter 96-06 modifications.

The ECCS and related pumps which must operate following the design basis accident include the residual heat removal, safety

injection, containment spray, centrifugal charging, component cooling water, and service water pumps.

Minimum available Net Positive Suction Head (NPSH) to the safety injection, centrifugal charging, and containment spray pumps occurs when all are taking suction from the refueling water storage tank (RWST) during the injection operation immediately following the design basis accident.

Since maximum required NPSH and minimum available NPSH occur at the runout flow for the pumps, this flow was assumed for calculation purposes. The temperature of the RWST water varies between 40°F and 100°F.

Available NPSH at runout flow to these pumps at both the high and low temperatures was calculated. Suction line friction losses are higher at 40°F, but the higher vapor pressure of 100°F water leaves less available NPSH to the pumps. Friction losses were calculated using the conservative pipe and fitting resistances given in the Crane Co. Technical Paper Number 410.

The residual heat removal pumps take suction during the post-accident recirculation phase from the containment sump. The water is at a higher temperature than during injection, but the elevated containment pressure following a design basis accident somewhat offsets the higher vapor pressure of the water; however, no credit is taken for this. In addition, the piping to the pump suctions is quite direct; hence, friction losses are small.

Service water pumps are vertical turbine pumps taking suction directly at the plant intake. Suction location is 44 inches below low-low water elevation (Elevation 76 feet), temperature 90°F. The component cooling water pumps have suction head tanks which maintain pressure in the closed system equal to the maximum elevation of the system piping.

Either of two subsystems containing a pump and associated valving and spray headers are independently capable of delivering 2600 gpm.

The design basis is to provide sufficient heat removal capability to maintain the post-accident containment pressure below the design pressure assuming that the core residual heat is released to the containment as steam.

A second purpose served by the Containment Spray System is to remove elemental iodine from the containment atmosphere should it be released in the event of a LOCA. The analysis of offsite thyroid dose after a hypothetical LOCA is presented in Section 15. Iodine removal effectiveness is described in Section 6.2.3.

The Containment Spray System is designed to operate over an extended time period, following a primary coolant system failure, as required to restore and maintain containment conditions at near atmospheric pressure. It has the capability of reducing the containment post-accident pressure taking into account any reduction in capacity due to a single failure as defined in Section 6.2.2.

Portions of other systems which share functions and become part of the Containment Spray System, when required, are designed to meet the criteria of this section. Any single failure of an active component in either spray subsystem does not degrade the minimum containment cooling as defined in Section 6.2.2 or fission product removal capability of the Containment Spray System, as the containment pressure-temperature analysis in Section 15 assumes the most restrictive single failure.

Those portions of the spray systems located outside of the containment which are designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment meet the following requirements:

1. Adequate shielding to maintain radiation levels within the guidelines of 10CFR100 (Section 11.2).

2. Collection of discharges from pressure relieving devices into closed systems.

3. Means to limit radioactivity leakage to the environs, consistent with guidelines set forth in 10CFR100.

System active components are redundant. System piping located within the containment is redundant and separable in arrangement.

All portions of the system located within containment are designed to withstand, without loss of functional performance, the post-accident containment environment and operate without benefit of maintenance for the duration of time to restore and maintain containment conditions at near atmospheric pressure.

Table 6.2-1 tabulates the codes and standards to which the Containment Spray System components are designed.

6.2.2.1.2 System Design

System Description

Adequate containment cooling and iodine removal are provided by the Containment Spray System shown on Figures 6.2-4A and -B whose components operate in sequential modes. These modes are:

1. Spray a portion of the contents of the refueling water storage tank (RWST) into the containment atmosphere using the containment spray pumps. During this mode, the contents of the spray additive tank (sodium hydroxide) are mixed into the spray stream to enhance the iodine removal capability of the Containment Spray System.

System and Component Testing

Active components of the Containment Spray System were adequately tested both in pre-operational performance tests in the manufacturer's shop and in place after installation. Thereafter, periodic tests are also performed after component maintenance.

Means are provided to test initially, under conditions as close to design as is practical, the full operational sequence that would bring the Containment Spray System into action.

The containment spray pumps can be tested individually by opening the valves in the miniflow line. Each pump, in turn, can be started by operator action and checked for flow establishment. The spray injection valves can be tested with the pumps shut down.

The spray additive tank valves can be opened periodically for testing. The contents of the tank will be periodically sampled to determine that the proper solution is present.

During these tests, the equipment will be visually inspected for leaks. Leaking seals, packing, or flanges will be tightened to eliminate the leak. Valves and pumps will be operated and inspected after any maintenance to ensure proper operation.

Permanent test lines for all spray loops are located so that the system, up to and including the isolation valves at the spray header, can be tested. These isolation valves can be checked separately.

Flow bypass through the eductors was checked during the initial preoperational tests of the Spray System. Subsequent system tests will be made with the spray additive tank bypass valves closed.

The air test lines for checking spray nozzles connect downstream of the isolation valves. Air flow through the nozzles is monitored as required by the Technical Specifications.

The functional test of the ECCS described in Section 6.3 includes the operation of the Containment Spray System. A test signal simulating the containment spray initiating signal is used to demonstrate operation of the Spray System up to the isolation valve on the pump discharge.

Spray Nozzles

The spray nozzles are of a hollow-cone pressure nozzle design without any internal parts subject to clogging. The nozzles produce a drop size spectrum with a Sauter mean drop size less than 1000 microns with the spray pump operating at design conditions and the containment at design pressure and temperature.

During spray recirculation operation, the water is screened through a 1/4-inch mesh before leaving the containment sump. The spray nozzles are stainless steel and have a 3/8-inch diameter orifice. The nozzles are connected to four 360-degree ring headers of ring headers (alternating headers connected) of diameter 101 feet (Elevation 244 feet-6 inches), 53 feet (Elevation 266 feet-6 inches), 96 feet (Elevation 247 feet), 48 feet (Elevation 269 feet).

The nozzles and headers are so oriented as to maximize coverage of the containment volume.

6.2.2.2 Containment Fan Cooling System

6.2.2.2.1 Design Basis

The Containment Fan Cooling System is designed to recirculate and cool the containment atmosphere in the event of a LOCA and thereby ensure that the containment pressure will not exceed its design value of 47 psig at 271°F (100-percent relative humidity). Although the water in the core after a LOCA is quickly subcooled by the SIS, the Containment Fan Cooling System is designed on the

conservative assumption that the core residual heat is released to the containment as steam.

The Containment Ventilation System (Section 9.4) which includes the Containment Fan Cooling System, is designed to remove the normal heat loss from equipment and piping in the reactor containment during plant operation and to remove sufficient heat from the reactor containment, following the initial LOCA containment pressure transient, to keep the containment pressure from exceeding the design pressure. The fan cooler units continue to remove heat after the LOCA and reduce the containment pressure close to atmospheric within the first 24 hours.

In addition to the design bases specified above, the following objectives are met to provide ESF functions:

1. Each of the five fan-cooler units is capable of transferring heat at the rate of at least 18,047 Btu/sec (65 x 10^6 Btu/hr) from the containment atmosphere at the post-accident design conditions, i.e., a saturated air-steam mixture at 47 psig and 271°F. This heat transfer rate is that assigned to the fan-cooler units in the accident analyses of Section 15.

   The establishment of basic heat transfer design parameters for the cooling coils of the fan-cooler units, and the calculation by computer of the overall heat transfer capacity are discussed in Section 15.4.

2. In removing heat at the design basis rate, the cooler coils are capable of discharging the resulting condensate without impairing the air flow capacity of the fan coolers and without raising the exit temperature of the service water to the boiling point. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post-accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture, such as by operation of the Containment Spray System, will therefore have essentially no effect on the heat removal capability of the coils.

In addition to the above design bases, the equipment is designed to operate at the post-accident conditions of 47 psig and 271°F for 3 hours, followed by operation in an air-steam atmosphere at 20 psig, 219°F for an additional 21 hours. The equipment design will permit subsequent operation of an air-steam atmosphere at 5 psig, 152°F for an indefinite period.

All components are capable of withstanding or are protected from d/ps which may occur during the rapid pressure rise to 47 psig in 10 seconds.

Portions of other systems which share functions and become part of this Containment Cooling System, when required, are designed to meet the criteria of this section. Neither a single active component failure in such systems during the injection phase nor an active/passive failure during the recirculation phase will degrade the heat removal capability of containment cooling.

Where portions of these other systems are located outside of containment, the following features are incorporated in the design for operation under post-accident conditions:

1. Means for isolation of any section.

2. Means to detect and control radioactivity leakage into the environs, to the limits consistent with guidelines set forth in 10CFR100.

3. The RCFC (or CFCU) units are able to deliver their designed cooling capacity under all normal and abnormal conditions. Two-phase flow regions within the RCFC cooling coils following a LOCA/MSLB concurrent with a station blackout event are prevented by maintaining the RCFC cooling coils water solid during all normal and abnormal conditions.

   The waterhammer issues and modifications to the SW system (see Section 9.2, Service Water System) addressed in Generic Letter 96-06, preclude the possibility of the detrimental heat transfer effects resulting from the development of two-phase flow regions within the RCFC cooling coils.

6.2.2.2.2 System Description

The Containment Fan Cooling System is illustrated on Figures 9.4-4A and B.

Individual system components and their supports meet the requirement for Class I (Seismic) structures and are isolated from fan vibration.

The Containment Fan Cooling System consists of five air handling units, each including motor, fan, motor heat exchanger, cooling coils, roughing filters, dampers, duct distribution system, instrumentation, and controls. The units are located on the operating floor, between the containment wall and the polar crane wall.

Each fan is designed to supply a nominal 110,000 cfm during normal operation and 39,000 cfm during accident operation. The fans are direct driven, centrifugal type, and the coils are plate fintube type. Each air handling unit is capable of removing at least 65 x 10^6 Btu/hr from the containment atmosphere under accident conditions. A minimum of 2500 gpm of service (cooling) water is supplied to each unit during accident conditions. The design maximum river water inlet temperature is 90°F, which results in an outlet temperature of 160°F under design basis conditions or 191°F for zero fouling case. Assuming a single active failure of the flow control valve to change the setpoint from normal flow to the accident flow, the outlet temperature could reach 221°F.

The Section 15 accident analysis also assumes an additional degradation in the heat transfer rate of 10% for the first two minutes of diesel powered fan cooler operation. This assumption accounts for nitrogen gas that could be released from solution from the service water system accumulators that provide a part of the resolution of Generic Letter 96-06.

Duct work distributes the cooled air to the various containment compartments and areas. During normal operation, the flow sequence through each air handling unit is as follows: inlet dampers, roughing filters, cooling coils, fan, discharge header. During post-accident operation, air is drawn through a moisture separator, a post-accident high-efficiency particulate air (HEPA) filter section and cooling coils and is discharged to the duct header.

Tight closing dampers isolate the post-accident filter section from the normally operating components. These dampers are tripped to the accident position upon either manual or automatic actuation of the respective fan. Electrically operated four-way solenoid valves control instrument air to the damper control cylinders. On a loss of either control air or control power the dampers fail to the accident (open) position.

The Fan Cooling System is actuated (in the post-accident mode) by a safety injection signal. The accident analysis assumes the CFCU initiating safety injection signal was containment high pressure because this is the limiting time delay case. Either all five fans or a minimum of three fans are started by the safeguards equipment controller, depending on the availability of emergency power.

A flow switch at each fan indicates whether air is circulating in the intended normal or post-accident flowpath. Indication and alarms are provided in the Control Room.

Flow Distribution and Flow Characteristics

The location of the distribution ductwork outlets, together with the location of the fan cooler unit inlets, ensures that the air will be directed to all areas requiring ventilation before returning to the units.

In addition to ventilating areas inside the periphery of the polar crane rail, the distribution system also includes branch ducts located at opposite extremes of the containment wall for ventilating the upper portion of the containment. These ducts extend upward along the containment wall as required to permit the throw of air from the ducts to reach the dome area and assure that the discharge air will mix with the atmosphere.

The air discharged inside the periphery of the polar crane rail circulates and rises above the operating floor through openings around the steam generators where it mixes with air displaced from the dome area. This mixture is returned to the fan coolers located on the operating floor. The temperature of this air will be essentially the design ambient for the containment vessel (120°F average maximum).

The steam-air mixture from the containment entering the cooling coils initially during the accident will be at approximately 271°F and have a density of 0.172 pounds per cubic foot. Most of the water vapor will condense on the cooling coil, and the air leaving the fan cooler will be saturated at a temperature slightly below 271°F.

With a flow rate of 39,000 cfm from each of 5 fans under accident conditions and a containment net free volume of 2,620,000 ft^3, the recirculation rate with five fans operating is approximately 4.5 containment volumes per hour.

Cooling Water for the Fan Cooler Units

The cooling water requirements for all five fan cooler units during a LOCA and recovery are supplied by the Service Water System. The Service Water System is described in Section 9. The design basis river water temperature for service water to the containment fan coolers is 90°F, although river water temperatures throughout the year are normally less. The service water temperature rise through the containment fan coolers is approximately 8°F for normal operation. In the unlikely event of an accident, this temperature rise will be a maximum of approximately 70°F* for a period of less than 1 hour, after which it will decrease. It is not expected that any significant amount of calcium carbonate precipitation on the heat exchanger surfaces will occur at these temperatures, and, therefore, there will be no subsequent plugging of the fan coolers.

As part of the issues addressed in Generic Letter 96-06, certain design constraints have been applied to the SW system for the Containment Cooling System CFCU (RCFC)

*101°F for the zero fouling case and 131°F for the accident and single active failure of the flow controller to reset to accident flow.

units. These constraints and modifications are discussed in further detail in Section 9.2 (Service Water System). The following constraints apply to the cooling water for the fan cooler units:

1. Voids or column separation induced by siphoning effects, or changes in elevation cannot be tolerated in the SW system. These locations must remain water solid during all operating conditions.

2. The pressure in the flowing portions of the SW system must remain above the fluid saturation pressure for all operating conditions. Flashing or boiling resulting from increased temperatures or decreased pressures cannot occur. This constraint precludes the possibility of waterhammer or other hydraulic events due to steam bubble collapse, two-phase flow, or steam propelled water slugs.

3. The SW system containment penetrations and the containment closed systems must have pressure relief capability, or be shown not to be susceptible to large increases in internal pressure due to increased fluid temperatures. This constraint prevents failures of the containment boundary due to thermally induced overpressures.

Service water discharge from the cooling coils is monitored for radioactivity by routing a small bypass flow from each fan cooler unit through a radiation monitor. An alarm is annunciated in the control room upon detection of high radioactivity in an effluent line.

Flow and temperature indication is provided outside containment for service water flow to and from each fan cooler unit. Abnormal flow alarms for inservice fan cooler units are provided in the control room.

During normal operation, a dual setpoint service water flow controller will position the flow control valve to give the required 700 gpm flow. During conditions of safety injection, a signal to the controller changes the setpoint to provide a minimum flow of 2500 gpm to the RCFC cooling coils. The control valve closes when the fan cooler unit is not in use.

The solenoid valve associated with the flow control valve is de-energized to apply control air header pressure to the valve operator (closing the valve) whenever the RCFC fans are not running, or DC power is lost. The solenoid valve would then be energized to apply the pneumatic control signal to the flow control valve operator when the RCFC fan is operating in high or low speed.

Components

Roughing and HEPA Filters

The roughing filters in each fan cooler unit are designed to remove the larger particles of suspended dust and dirt from the containment atmosphere during normal power operation, normal reactor shutdown and loss of offsite power conditions. Removal of the particles also prevents buildup on the cooling coils, thus avoiding a reduction in heat transfer.

The roughing filters are arranged in two banks, each consisting of structural steel frame and removable filter cells. Each filter cell contains a fiberglass media which is capable of removing 90 percent of visible dust particles. The media efficiency is 70 percent on National Bureau of Standards type test ratings.

The HEPA filters in each fan cooler are provided to remove any particulate matter from the containment atmosphere. The HEPA filters are arranged in a structural steel frame and are individually removable. The filter media is fiberglass with asbestos separators and is capable of collecting 99 percent of particles 0.3 micron and larger in size from a saturated (100-percent relative humidity) 271°F atmosphere processed through the filter at 250-300 fpm. The HEPA filter media meets MIL-F-51079 and MIL-STD-282.

Fan-Motor Units

The five containment cooling fans are of the centrifugal, nonoverloading direct drive type. Each fan provides a minimum flow rate of 39,000 cfm when operating against the system resistance existing during accident conditions (0.172 lb/ft^3 density, a containment pressure of 47 psig, and temperature of 271°F).

The two-speed containment fan cooler motors are totally enclosed, fan cooled (TEFC), 300 hp (high speed), induction type, 3 phase, 60 cycle, 1200 RPM, 460 volt with ample insulation margin. At low speed the motor delivers 100 hp. Insulation is Class F (NEMA rated total temperature 155°C) Westinghouse Thermalastic. It is impregnated and coated to give a homogeneous insulation system which is highly impervious to moisture. Internal leads and the terminal box-motor interconnection are given special design consideration to assure that the level of insulation matches or exceeds that of the basic motor system. At incident ambient and/or accident load conditions (271°F and 100 hp), the motor insulation hot spot temperature is not expected to exceed 113°C.

Fan cooler motors are cooled by an air-to-water heat exchanger which is connected to the motor to form an entirely enclosed cooling system. Air movement is through the heat exchanger and is returned to the motor. Two vent valves permit containment ambient air to enter the cooling compartment (on increasing containment pressure) so the motor bearings will not be subjected to an excessive d/p. An open condensate drain line will enable the cooling compartment to equalize with the containment pressure as containment pressure is reduced by the motor heat exchanger. Cooling water is supplied by the Service Water System (SWS).

The motors are equipped with high temperature grease lubricated ball bearings to withstand the design basis incident ambient temperatures. Continuous bearing temperature monitoring is provided which will alarm in the control room. Fan motor leads are brought out of the frame through a seal and into a cast iron sealed explosion-proof type of conduit box. Overload protection for the fan motors is provided at the switchgear by overcurrent trip devices in the motor feeder breakers. The breakers can be operated from the Control Room and can be reclosed from the control room following a motor overload trip.

In addition to the usual quality control tests which are performed to give assurance that the motors meet design specifications, special tests are performed to demonstrate that insulation margins are built in as expected. The completely wound stators are given a special high potential test to ground. The stators are immersed in water, meggered, and given a high potential test while immersed. After passing the water tests, the motor is baked and given a final coating dip. The stator and rotor are then baked again.

Cooling Coils

Coils are fabricated of AL-6X tubing. The heat removal capability of the cooling coils is at least 65 x 10^6 Btu/hr per fan cooler unit at saturation conditions (271°F, 47 psig). The design internal pressure of each coil is 150 psig and the coils can withstand an external pressure of 47 psig at a temperature of 271°F without damage.

Each recirculating unit consists of 12 coil units mounted in two banks of 6 coils high. These banks are located one behind the other for horizontal series air flow, and the tubes of the coil are horizontal with vertical fans.

A moisture separator in each fan cooler removes the larger droplets of suspended moisture from the containment atmosphere in the event of a LOCA. Removal of the droplets prevents any significant water deluge over the face of the HEPA filters and thus avoids a serious reduction in filter effectiveness. The separator consists of a structural steel frame with removal separator elements. Each element is capable of removing 95 percent of water droplets 10 microns and larger in size, at the rate of 0.35 lb of water per 1000 cfm of processed atmosphere traveling at 350 to 500 fpm through the element.

The coils are provided with drain pans and drain piping to prevent flooding during accident conditions. This condensate is drained to the containment sump.

Ducting

The ducts are designed to withstand the sudden release of RCS energy and energy from associated chemical reactions without failure due to shock or pressure waves by incorporation of damper along the ducts which open at slight overpressure (3.0 psi). The ducts are designed and supported to withstand thermal expansion during an accident. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1.

Ducts are of welded and flanged construction. All longitudinal seams are welded. Where flanged joints are used, joints are provided with gaskets suitable for temperatures to 300°F. Ducts are constructed of galvanized sheet metal.

Dampers

All air control dampers that are an integral part of the fan coolers are designed to Class I seismic criteria. The damper construction is designed to withstand the design basis earthquake (DBE) concurrent with the pressure transients, thermal energy, and chemical activity resulting from a LOCA. Each damper is constructed of specially painted steel, with multiple blades that operate in unison and edge seals to minimize air leakage.

The backdraft damper at the discharge of each fan cooler is a normally closed counter-weighted device that opens automatically when the fan operates. It is designed to remain intact and operable during any LOCA by withstanding an approximate 7-psi air pressure surge over a 10-second period. This damper prevents the pressure surge from damaging the fan-motor assembly.

Two-position shut-off dampers are provided at each fan cooler to divert air flow through the HEPA filters and moisture separators during any LOCA or through the roughing filters during normal operation. The roughing filter dampers are normally open and fail closed. The HEPA filter dampers are normally closed and fail open. Both sets of dampers revert to their fail positions after a safety injection signal.

Each two-position shut-off damper is provided with redundant pneumatic operators that can provide 150 percent of the design operating torque. Each damper assembly is designed to remain intact and operable during any LOCA by withstanding a 3-psi air pressure surge over a 10-second period.

The fan coolers are equipped with pressure relief dampers in the filter enclosures. These dampers are normally closed counter-weighted devices that open progressively as the d/p across them exceeds 0.25 psi. In the event of a LOCA, the pressure-relief dampers limit the d/p to 3 psi and thus maintain

the structural integrity of the fan coolers during the pressure transient.

6.2.2.2.3 Design Evaluation

Range of Containment Protection

The Containment Fan Cooling System provides the design heat removal capacity for the containment following a LOCA assuming that the core residual heat is released to the containment as steam. The system accomplishes this by continuously recirculating the air-steam mixture through cooling coils to transfer heat from containment to service water. Any of the following combinations of equipment provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value:

1. All five containment fan cooler units.

2. Both containment spray loops.

3. Three containment fan cooler units and one containment spray loop.

The performance of the Containment Fan Cooler System in pressure reduction is discussed in Section 15.

System Response

Automatic starting of the standby fan cooler units (under design conditions, up to four of the fans, and two service water pumps operate during normal power operations for containment ventilation) and the related emergency power equipment is designed so that the required air flow and cooling water flow for an accident condition is reached within the time delay for starting fan cooler units assumed in the containment pressure analyses.

(This text has been deleted)

The water valves and air dampers are actuated to the accident position by closure of the fan cooler low speed breaker.

Single Failure Analysis

A failure analysis for all active components of the system shows that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2-7.

The analysis of the LOCA presented in Section 15 is consistent with the single failure analysis.

Reliance on Interconnected Systems

The Containment Fan Cooling System is dependent on the operation of the SWS. Cooling water to the coils is supplied from the SWS. Six service water pumps are provided, only two of which are required to operate during the post-accident period.

Shared Function Evaluation

Table 6.2-8 is an evaluation of the main components which have been discussed previously and a brief description on how each

3. Safety injection recirculating suction line from the containment sump to the suction of the RHR pumps. Redundant isolation protection is provided by normally closed motor operated valves inside protective chambers outside of containment and the closed system (RHR) outside the containment.

4. Containment instrument lines (see below).

5. The main feedwater lines are provided with one stopcheck valve (BF22) outside containment. These valves include remote-manual motor operators.

6. RHR pump discharge to cold leg Safety Injection. Redundant isolation is provided by the remote manual (SJ49) valves located outside containment and the RHR closed system outside containment. This is considered an acceptable isolation barrier per the "other defined basis" in ANSI N271-1976. This standard is endorsed by Regulatory Guide 1.141.

7. ECCS relief line discharge to the containment sump. Redundant isolation is provided by a check valve inside containment (PR25) and the closed system outside the containment.

8. Service Water system to and from the Containment Fan Coil Units. Redundant isolation is provided by remote manual valves outside containment and the closed Nuclear Class III system inside containment. Original system design complied with AEC General Design Criteria #53 and the system meets the definition for a Safety Class 2 system.

9. Component Cooling to and from the Excess Letdown Heat Exchanger. Redundant isolation is provided by automatic isolation valves outside containment and the closed Nuclear Class III system inside containment. Original system design complied with AEC General Design Criteria #53 and the system meets the definition for a Safety Class 2 system.

10. Main Steam supply lines to the Auxiliary Feed Pump Turbine, Radiation Monitors and the Steam Safety Valves support struts. These essential system branch lines off the Main Steam penetrations only utilize a single isolation barrier being the closed system inside containment. The calculated release through these paths is already bounded by the accident analysis for a primary to secondary leak and a complete blowdown of the Steam Generator.

Instrument Lines

Instrument lines which penetrate the containment are the following:

1. The containment pressure instrument used to initiate safeguards consists of four instrument lines penetrating the containment. Each line consists of a sealed, filled measuring system whose isolation consists of a diaphragm-type sensor which separates the containment atmosphere from the seal fluid and another diaphragm in the transmitter which separates the seal from the atmosphere outside the containment.

2. The containment air sample radiation monitor normal inlet and outlet sample lines are each equipped with two automatic trip valves, one inside and one outside the containment, which close upon receipt of a containment isolation phase A signal. The backup inlet and outlet sample lines are normally closed and under administrative control with two remote operated isolation valves, one inside and one outside the containment for each line.

3. The containment pressure instrument used for wide range monitoring consists of two instrument lines penetrating the containment. Each line consists of a sealed, filled measuring system whose isolation consists of a diaphragm-type sensor, which separates the containment atmosphere from the seal fluid and another diaphragm in the transmitter, which separates the seal from the atmosphere outside containment.

Anti-vortex plates are installed in the containment spray suction line from the RWST. Verification of vortex control in the containment sump is discussed in Section 6.3.4.4.

The temperature of the water in the RWST is prevented from dropping below 32°F by automatic initiation of a Circulating and Heating System, which draws water from the tank through the Safety Injection System suction pipe and the Containment Spray System suction pipe. The water is then pumped through a heat exchanger located in the Auxiliary Building and enters the tank via the return line from the refueling water purification pump. Thus, the water in the tank and the water in the connecting piping is heated and circulated.

The instrumentation that actuates the Heating System senses the temperature in the SIS suction pipe. This temperature and the temperature of the return water are monitored and alarmed in the Control Room. The system has provisions for local manual actuation.

Electrical heat tracing is provided for the instrument connections to the tank and for that portion of the tank drain piping which could otherwise freeze. Thermal insulation is also provided for the exposed piping.

Valves 1SJ30 and 1SJ69 (in the RWST suction line to the ECCS pumps) are provided with the same type of redundant position indication as the accumulator discharge valves, described in Section 6.3.2.15.

Residual Heat Removal Pumps

The two RHR pumps are vertical electric motor driven single stage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or of equivalent corrosion resistant material.

A minimum flow bypass line is provided for the pumps to recirculate through the residual heat exchangers and return the cooled fluid to the pump suction should these pumps be started with their normal flow paths blocked. Once flow is established to the RCS, the bypass line is automatically closed. This line prevents deadheading the pumps and permits pump testing during normal operation.

Centrifugal Charging Pump

The two centrifugal charging pumps are horizontal electric motor driven multistage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or equivalent corrosion-resistant material. Miniflow protection is provided during ECCS operation.

Safety Injection Pump

The two safety injection pumps are horizontal electric motor driven multistage pumps. All parts of the pump in contact with the pumped fluid are stainless steel or equivalent corrosion-resistant material. A minimum flow bypass line is provided on each pump discharge to recirculate flow to the RWST in the event that the RCS pressure is above the shutoff head of the pumps. In Unit 1, a 100 gpm test line is provided in parallel to the miniflow line. This line is used for inservice testing and is locked out at other times. A similar 100 gpm test line is not provided in Unit 2.

Pump Design, Materials, and Fabrication

The pressure-containing parts of the pumps are stainless steel castings conforming to ASTM A-351 Grade CF8 or CF8M, stainless steel forgings procured per ASTM A-182 Grade F304 and F316, or carbon steel forgings to ASTM A-181, Grade 1, clad with austenitic steel. Parts fabricated of stainless plate are constructed to ASTM A-240, Type 304 or 316. All bolting material conforms to ASTM A-193 and A-194.

Materials such as weld-deposited Stellite or Colmonoy are used at points of close running clearances in ~~the~~ pumps to prevent galling and to ensure continued performance ability in high velocity areas subject to erosion. In other cases, wear points are of ASTM A-420 Grade stainless steel, heat treated to give the required antigalling properties.

All pressure-containing parts of the pumps are chemically and physically analyzed and the results are checked to assure conformance with the applicable American Society for Testing and Materials' specification. In addition, all pressure-containing parts of the pump are liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Code. The acceptance standard for the liquid penetrant test is the ASME Pump and Valve Code.

Pump design is reviewed with special attention to the reliability and maintenance aspects of the working components. Specific areas include evaluation of the shaft seal and bearing design to determine that they are adequate for the specified service.

During pump fabrication and installation, where welding of pressure-containing parts was necessary, a welding procedure including joint detail was submitted for review and approval by Westinghouse.

This procedure included evidence of qualification necessary for compliance with Section IX of the ASME Code Welding Qualifications. This requirement also applied to any repair welding performed on pressure-containing parts. Subsequent to construction, Welding Procedure Specifications (WPS) are approved and qualified in accordance to the current requirements of Section IX of the ASME Boiler and Pressure Vessel Code.

The pressure-containing parts of the pump were assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump was given a complete shop performance test in accordance with Hydraulic Institute Standards. The pumps were run at design flow and head, shut-off head and three additional points to verify

performance characteristics. Where NPSH is critical, this value is established at design flow by means of adjusting suction pressure.

A qualitative analysis shows that any flooding resulting from a leak in one pumping train will not incapacitate the redundant pump.

Heat Exchangers

The two residual heat exchangers of the RHR system cool the recirculated sump water. These heat exchangers are sized for the cooldown of the RCS. The design parameters of the heat exchangers are presented in Section 5.5.

The residual heat exchangers are designed to the ASME Code and to conform to the requirements of the Tubular Exchanger Manufacturers' Association for Class R heat exchangers.

Additional design and inspection provisions include:

1. Confined-type gaskets

2. General construction and mounting brackets suitable for the plant seismic design requirements

3. Tubes and tube sheet capable of withstanding full shell side pressure and temperature with atmospheric pressure on the tube side

4. Radiographic inspection in accordance with Sections UW-11, UW-12-b, and UW52 of ASME Section VIII

5. Ultrasonic inspection in accordance with Paragraph N-324.3 of Section III of the ASME Code of all tubes before bending

6. Penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts

7. A hydrostatic test duration of not less than 30 minutes

8. The witnessing of hydro and penetrant tests by a qualified inspector

9. A thorough final inspection of the unit for workmanship and the absence of any gouge marks or other scars that could act as stress concentration points

10. A review of the radiographs and of the certified chemical and physical test reports for all material used in the unit.

The residual heat exchangers are conventional vertical shell and U-tube type units. The tubes are seal welded to the tube sheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube bundle. Each unit has a SA 515GR70 carbon steel shell, SA-213 TP-304 stainless steel tubes, SA-105 with Type 304 stainless steel overlay channel cover and a tube sheet of forged steel SA-105 GR.III with 1/4-inch minimum TP-304 weld overlay.

Valves (General)

Design features employed to minimize valve leakage include the following:

1. Other valves that are normally open, except those valves which perform a control function, are provided with backseats to limit stem leakage.

2. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

3. Relief valves are enclosed, i.e., they are provided with a closed bonnet and discharge to a closed system or the containment sump.

4. Control and motor operated valves (3 inches and above) exposed to recirculation flow have double packed stuffing boxes and stem leakoff connections to the Waste Processing System.

All parts of valves used in the SIS in contact with borated water are austenitic stainless steel or equivalent corrosion-resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of safety injection or isolation of the system have remote limit position indication in the control room.

Valving is specified for exceptional leak tightness. All valves, except those which perform a control function, are provided with backseats that are capable of limiting leakage to less than 1.0 cc per hour per inch of stem diameter, assuming no credit taken for valve packing. Those valves that are normally open are backseated. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves discharge to an enclosed system or the containment sump. Control and motor-operated valves, 3 inches and above that are exposed to recirculation, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the Equipment Drain System.

The check valves that isolate the ECCS from the RCS are installed near the reactor coolant piping to reduce the probability of an injection line rupture causing a LOCA.

3. Residual heat removal

The motors are designed in accordance with the National Electric Manufacturers' Association (NEMA) Standards. These standards are used by the industry and provide requirements for construction, test, performance, and manufacture of ac and dc motors and generators, that by experience demonstrate a high quality level. (NEMA, Standard Publication for Motors and Generators, No. MG 1-1967.)

Emergency Core Cooling System motors are specified to an Equipment Specification and the following design classifications:

1. Drip proof enclosure

2. Class B insulation system or better

3. Service factor rating of 1.15

4. 80 percent starting voltage capability.

The integrity of the insulation system is considered of prime importance. To assure this integrity, motors are sized such that NEMA temperature limits for the service factor rating of the motor are not exceeded (NEMA MG 1).

Table 6.3-7 shows system parameters and brake horsepower for both normal and accident conditions. The brake horsepower requirements are well below NEMA horsepower ratings. These motors will operate below the temperature limits as specified by NEMA MG 1. Further, complete engineering tests are performed on all prototype motor frame sizes to confirm design calculations.

Motors Outside the Containment

Motor electrical insulation systems are supplied in accordance with USAS, IEEE, and NEMA standards and are tested as required by

such standards. Temperature rise design selection is such that normal long life is achieved even under accident loading conditions.

Criteria for motors of the ECCS require that under normal plant operating conditions the motors operate below their nameplate rated horsepower, i.e., below a 1.0 service factor. For no other anticipated operating mode including safeguards operation do the motors exceed the maximum rating allowed by the nameplate, including their specified 1.15 service factor.

Motors Inside the Containment (Valve Motor Operators)

Tests which demonstrate the adequacy of valve motor operators to be functional after exposure to high temperatures, pressures, and radiation have been conducted. The results of the tests are confirmed in Reference 1.

Containment Sump

The physical arrangement of the containment sump is shown on Figure 6.3-2. All water entering the containment sump will have been strained either by the drain trench covers (which have 3/16-inch diameter holes drilled in them), by the floor drain gratings, or by the large inverted basket-type strainer installed on the containment sump cover (see Figure 6.3-3). An anti-vortex baffle minimizes the possibility of pump cavitation through optimal placement based on model tests (2).

The sump design differs from Regulatory Guide 1.82 in the following ways:

1. The small drainage sump for collecting and monitoring normal leakage within the containment is at the same location as the RHR sump. The Liquid Radwaste and RHR Systems share a common sump. A weir plate is installed to isolate normal drainage from the RHR pump suction.

2. The majority of containment sump screening consists of two-level horizontal screens.

Blockage of drains and containment sump screens will not be caused by circulation materials following an accident. Because of the structural nature of the insulation, large quantities of this material would not be dislodged from pipes in which breaks could occur or from surrounding pipes due to jet impingement. Reflective, totally encapsulated, and semi-encapsulated materials are designed to withstand severe loadings. Only the material directly adjacent to a high energy pipe break would be dislodged from the pipe. Although material directly in the path of a jet stream may become saturated, the lagging or strapping system will keep it on all insulated surfaces.

The following is a summary of insulation materials used inside containment:

Reflective: This is an all-metallic stainless steel insulation. This material is used on the RCS.

Encapsulated: This is a ceramic fiber insulation "cera-blanket" totally enclosed in a rigid stainless steel structure. This material is used on the ECCS piping and equipment in the containment.

Semi-Encapsulated: This application of "cera-blanket" insulation utilizes an outer heavy gage stainless steel surface with an interior surface of formed stainless steel foil or heavy gage stainless steel channels and straps (panel insulation). Foil-enclosed insulation is used for heat retention on Nuclear Class 3 piping and

equipment while panel insulation is used on the steam generators for Unit 2.

Min "K": This is a high-efficiency powder-like insulation totally enclosed in stainless steel. Small amounts of this insulation are used on the RCS where physical arrangement does not permit the use of thicker reflective insulation.

Fiberglass: This is a fibrous insulation covered by stainless steel and a vapor barrier used to prevent sweating of cold water systems (Component Cooling and Service Water).

Fiberglass With Blanket (Nukon Insulation): This fibrous glass insulation is enclosed in woven fibrous glass fabric between two layers of fiberglass scrim sewn to the insulation. This material is used on the Pressurizer and the Unit 1 Steam Generators. On most areas of the Pressurizer and the Unit 1 Steam Generators where this material is used, this insulation is covered with a stainless steel jacket or a stainless steel mesh.

Calcium Silicate: This rigid solid insulation is used on straight portions of the Feedwater and Main Steam Systems. This material is also covered with stainless steel. Welds in these systems are covered with encapsulated insulation.

Mineral Wool: This fibrous insulation is applied to the lower 34 feet of the containment liner and is also covered with stainless steel lagging and a vapor barrier.

Fiberglass Blanket: This fiberglass blanket material is jacketed with fiberglass fabric impregnated with silicone. This insulation is used as anti-sweat insulation on Service Water piping of 3" & 2" dia. at CFCUs in the Containment Building Units 1 & 2.

6.3.5.4 Level Indication

Refueling Water Storage Tank Level

The level of water in the RWST is continuously measured by two separate instrument channels (Unit 2 is provided with four instrument channels) with readouts on the main control board. Alarms are set at the proper level to initiate the switchover from injection to cold leg recirculation.

Accumulator Water Level

Each accumulator tank has two level measuring instruments with readouts on the main control board. Each instrument is set to alarm if the tank level falls or rises by more than a set amount from the normal operating level.

Boric Acid Tanks Level

Two level indicators give indication and alarm in the Control Room.

Containment Building Sump Level

The Containment Building has two interconnected by piping sumps - containment recirculation sump and Reactor Building sump. The containment recirculation sump has two redundant sump water level indicators on the console bezel in the main control room. Each of these sumps has a high level alarm on the overhead annunciator.

6.3.5.5 Valve Position Indication

Valve positions which are indicated on the control board are done so by a "normal off" system; i.e., should the valve not be in its proper position a bright white light will be lit and thus give a highly visible indication to the operator.

Accumulator Isolation Valve Position Indication

The accumulator motor-operated valves are provided with red (open) and green (closed) position indication lights located at the control switch for each valve. These lights are energized from independent power, other than the valve's control power, and actuated by valve motor-operator limit switches.

A monitor light that is on when the valve is not fully open is provided in an array of monitor lights that are all off when their respective valves are in proper position enabling safeguards operations. This light is energized from a separate monitor light supply and actuated by a valve motor-operated limit switch.

An alarm annunciator point is activated by both a valve motor-operator limit switch and by a valve position limit switch activated by stem travel whenever accumulator is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked). A separate annunciator point is used for each accumulator valve. The motor-operator limit switch alarm will be recycled at approximately 1 hour intervals to remind the operator of the improper valve lineup.

6.3.6 References for Section 6.3

1. Igne, E. G. and Locante, J., "Environmental Testing of Engineered Safety Features Related Equipment (NSSS-Standard Scope)," WCAP-7410-L (Proprietary) December 1970 and WCAP-7744 (Non-Proprietary), Volume 1, August 1971, and Volume 2, September 1970.

2. Nystrom, J. B., "Experimental Evaluation of Flow Patterns in an RHR Sump With Simulation of Screen Blockage--Salem Nuclear Station," Alden Research Center, Worcester Polytechnic Institute, January 1981.

3. Nuclear Safety Advisory Letter NASL-93-016, Revision 1, "Containment Spray System Issues," Westinghouse, October 4, 1993.

6.4 HABITABILITY SYSTEMS

The Salem Generating Station (SGS) Units 1 and 2 control rooms are located within a common Control Room Envelope (CRE). The control rooms are located at elevation 122 feet of the Auxiliary Building and contains those controls and instrumentation necessary for operation of the units under normal and abnormal conditions. The Operations Support Center (OSC) is located within the CRE towards the west side of the control rooms. The CRE is continuously occupied by operating personnel under all operating conditions.

The facilities located within the CRE are designed to be habitable throughout the course of a design basis accident (DBA) and the resulting radiological condition.

6.4.1 Design Bases

The control room habitability system provides for the access and occupancy of the CRE during normal conditions, radiological emergencies, hazardous chemical emergencies and fire emergencies. The system design conforms with the intent of AEC General Design Criterion (GDC) 19 (1971) as described in Section 3.1. To this end, administrative procedures, shielding, ventilation system, radiological monitoring and the fire protection system are used.

The control room habitability system also conforms with the intent of AEC GDC 5 (1971), Sharing of systems, as described in section 3.1.

The control room habitability systems functional design was evaluated for each of the following conditions:

(1) Normal operating conditions

(2) Radiological conditions resulting from a DBA

(3) Hazardous chemical release

(4) Fire or smoke inside or outside the common control room

6.4.2 System Design

6.4.2.1 Control Room Envelope

The Control Room Envelope (CRE) consists of the following rooms and facilities that the control room habitability system provides for continuous occupancy to support personnel during normal operating conditions and for the duration of an accident:

(1) Units 1 and 2 Control Rooms

(2) Units 1 and 2 Data Logging Rooms

(3) Conference Room or Operations Support Center (OSC)

(4) Operations Superintendent Office

(5) Units 1 and 2 Control Room Supervisor Platform Area

(6) Operator Ready Room

The walls, recorder panels, doors, floors and ceiling for the rooms in the CRE make up the physical boundary between the adjacent rooms (relay, controls equipment, work control center, and HVAC equipment) and the outside environment.

As described in Section 12, the control room shielding consists of concrete walls, floor and roof. The control room shielding design ensures that the radiation exposure to the occupants in the control room are consistent with the GDC 19 limits.

6.4.2.2 Ventilation System Design

The control room ventilation system is designed to support personnel during normal operating conditions and during an accident. The design of the control room emergency air conditioning system conforms with the intent of the Regulatory Guide 1.52, Rev. 1 (1976) with the variances described in Section 3, Appendix 3A. Section 9.4 describes the control room ventilation and air conditioning systems.

As described in Section 11.4, the control room ventilation system consists of redundant radiation monitors that are shared by Units 1 and 2. Each unit consists of a digital microprocessor-based radiation monitor with two detection channels; one channel monitors the Unit 1 normal intake air and the other channel monitors the Unit 2 normal intake air. Each monitor provides actuation signals, based on high radiation, to the Unit 1 and 2 control area ventilation controls system.

Plant systems affecting control room habitability are the following:

(1)	Ventilation	(Section 9.4.1)
(2)	Fire Protection	(Section 9.5.1)
(3)	Communications	(Section 9.5.2)
(4)	Lighting	(Section 9.5.3)
(5)	Radiation Protection	(Section 11.4.1)
(6)	Shielding	(Section 12)

Air Conditioning Units (per unit):

Three 50% capacity package chiller units are provided, each consisting of a reciprocating compressor, cooling coil or chiller unit and water cooled condenser. Two 100% capacity chilled water pumps (one standby) circulate water through all three chiller units. During emergency conditions, two chillers are available per unit supplying 48°F (nominal) chilled water to each units CAACS and CREACS coils for the removal of the design heat loads based on summer design conditions.

6.4.2.3 Leak Tightness

The control room habitability system is designed to pressurize the CRE to equal to or greater than 1/8 inwc differential to adjacent rooms and the environment by providing a total of 2000 (nominal) scfm of filtered makeup air from a preferred selected intake. The Unit 1 and 2 control area ventilation system during an accident normally operates with two emergency filter trains providing 1000 (nominal) scfm of makeup air each, or during an abnormal alignment with a single emergency filter train providing 2000 (nominal) scfm makeup air. The pressurized CRE ensures contamination flow out of the CRE, thereby reducing operator dose.

6.4.3 System Operational Procedures

Procedures are provided for operating the control room habitability system in the required modes of operation to protect operating personnel in the control room during an emergency condition. During emergency conditions, the control room habitability system is initiated automatically upon an SI or high radiation signal or manually to place the system in the preferred mode of operation to protect operating personnel in the control room.

6.4.4 Design Evaluation

Table 6.4-3 summarizes data in the control area ventilation, which is described in detail in Section 9.4.1.

6.4.4.1 Normal Operation

During normal operating conditions, the control area ventilation system operates to supply cool filtered air to maintain ambient room temperatures for personnel comfort and instrumentation accuracy. The ventilation system is set to maintain room temperatures at a nominal temperature of 76□F. The normal operating limits and equipment design temperature limitations in the control room and adjoining control equipment room are described in Section 3.11.1.3. In this mode, most of the air inside the control room areas is recirculated with some quantity of makeup air introduced to maintain the CRE and control room areas at a positive pressure to minimize the infiltration of dust, smoke and other airborne contaminants. Both Units 1 and 2 control area ventilation systems provide cool filtered air to the CRE during normal operation.

6.4.4.2 Radiological Protection

The adequacy of the control room shielding is evaluated for normal operating and accident conditions in Section 12.

The adequacy of the control area ventilation system is evaluated for radiological emergencies in Section 9.4.1 and 15.4.1.9.

The Operations Support Center (OSC) is located within the protected CRE and is adequate to support operating personnel during normal operating conditions and for the duration of an accident.

6.4.4.3 Toxic and Chemical Gas Protection

Regulatory Guide 1.78 requires that hazardous chemicals, such as those indicated in Table C-1 of the Guide, be considered in an analysis of Control Room habitability if they are frequently shipped within a 5-mile radius of the station. The Guide also defines frequent shipments as being 50 or more trips per year for barge traffic and 10 or more trips per year for truck traffic. Chemicals stored or situated at distances greater than 5 miles from the facility need not be considered in the habitability analysis.

The Salem site is located in a rural area with no major manufacturing or chemical plants located with 5 miles of the site. The only major transportation route within 5 miles of the station is the Delaware River, with the intra-coastal waterway passing 1 mile west of the site.

The Salem Generating Station uses a hypochlorite biocide system, thus eliminating an onsite chlorine hazard. The Control Room is equipped with smoke and combustible detectors located in the air conditioning unit ducts. These detectors provide alarms in the Control Room in the presence of smoke or combustible hazards. The Control Room area fresh air intake ducts are equipped with redundant radiation monitoring systems which provide annunciation, automatically isolate the Control Room, and switch the ventilation system to the accident pressurized mode on high radiation detection. Sections 2.2.3.2 and 2.2.3.3 discuss and conclude that a release of any of the hazardous chemicals stored onsite or shipped past the site will not impact control room habitability.

Hazardous chemicals shipped past the Salem site occur infrequently. The frequencies of the deliveries are listed in Table 2.2-4. Regulatory Guide 1.78 requires a control room habitability evaluation for shipments of hazardous chemicals that are considered "frequent" shipments. The frequent criteria for river barges is 50 per year. As seen from Table 2.2-4, none of the hazardous chemicals shipped past the site exceed this criteria, therefore, a control room habitability evaluation is not required.

As previously mentioned, several chemicals are stored onsite that are considered hazardous. Sulfuric acid is stored in 4,000 and 2,250 gallon tanks in the SGS Turbine Buildings and it is stored in 16,000 gallon tanks at the HCGS. Calculations indicated that the toxicity limit found in Regulatory Guide 1.78 will not be exceeded in the control rooms during a postulated release at any of the sources.

Liquid nitrogen and nitrogen stored as a compressed gas is stored at various locations onsite. According to the criteria contained in Regulatory Guide 1.78, the largest single source should be evaluated for its impact on control room habitability. The sources evaluated at the SGS are the portable nitrogen tube trailers located in various areas throughout the SGS yard area and the (2) 3000 gallon tanks located behind Unit No. 1 & 2 Auxiliary Buildings. In addition to these sources, liquid nitrogen is also stored in 9,000 gallon tanks at the HCGS. Calculations indicated that the oxygen depletion is negligible in the control rooms during a postulated release at any of the significant sources.

Chemicals used as fire-fighting agents were evaluated. Carbon dioxide is stored on the 84 foot elevation of each of the Auxiliary Buildings. It is also stored at HCGS. Calculations indicated that the toxicity limit established in Regulatory Guide 1.78 as well as asphyxiation levels would not be exceeded during postulated releases at the significant sources. The Halon storage vessels are relatively small and do not contain the volume of Halon required to cause asphyxiation in the control rooms, therefore, a postulated release will not pose a danger to the control rooms.

Ammonium hydroxide is stored in a 3000 gallon vessel in the SGS Unit No. 1 Turbine Building. Evaluations concluded that the control rooms would remain habitable during a postulated release at the storage tank. The shipments to the site are considered "frequent" and are discussed in Section 2.2.3.3.

Hydrazine is stored in a 300 gallon vessel also in the Unit No. 1 side of the SGS Turbine Building. The calculations indicated that the control room concentrations will not exceed toxicity limits established in 29CFR Part 1910.1000, Subpart Z during a postulated release.

Aqueous sodium hydroxide is stored in various quantities and vessels at both the SGS and HCGS. Upon a release, sodium hydroxide vapors may form locally at the spill, but the physical properties of this chemical preclude the formation of a plume that will travel in the control room air intakes. The vapor pressure of aqueous sodium hydroxide is very low, especially as the concentration is increased. During a postulated release, mostly water will evaporate from the liquid pool, leaving the solid sodium hydroxide behind. The solid form of sodium hydroxide poses no danger to the control room due to its physical properties.

Helium is stored in 150 lb cylinders at both the SGS and HCGS. It is much lighter than air and upon a postulated failure of one of the cylinders, the helium would disperse rapidly into the atmosphere and not form a continuing plume.

Table 6.4-3 summarizes data on the Control Room Ventilation System, which is described in detail in Section 9.4.1.

systems' outputs are also separated to preserve the independence of redundant functions.

Redundant instrumentation and control cables are routed through separate containment penetrations to maintain independence.

The four independent channel signals are wired to four separate sets of analog protection racks located in the vicinity of the plant Control Room. These racks contain the isolation amplifiers which reproduce the sensed signal for use in the plant process control systems.

7.2.2.2 Design Basis for Protection Circuits

Both reactor trip and engineered safety features actuation functions are performed by the Solid State Protection System. Non-protective control type functions are also provided of which several can be classified as equipment protection.

The two redundant reactor trip logic channels are physically separated and electrically isolated from one another. The Reactor Protection System is comprised of identifiable channels which are physically, electrically, and functionally separated and isolated from one another. For additional information on this topic, see Reference 3.

The ac power feeds to the Solid State Logic System are in accordance with the split-bus concept shown on Figure 22 of WCAP-7488-L. The exceptions to the system depicted on Figure 22 with respect to Salem's configuration are: 1) the fuse in series to the DC power supplies via a filter are not in series with the filter. The DC power supplies are powered directly from the AC vital bus feeds. The fuse is in series with the input relays. 2) In Train A, vital instrument Buses I and IV (instead of Buses I and II) provide power to the DC power supplies while in Train B, Buses II and III (instead of Buses III and IV) provide power to the DC power supplies. 3) In Train B, Bus II provides power to the Slave Relays (instead of Bus IV). Refer to Figure 8.3-5 for the 115 VAC system.

The electrical supply and control conductors for redundant or backup circuits of the station have such physical separation as is required to assure that no single credible event will prevent operation of the associated function by reason of electrical conductor damage. Critical circuits and functions include power, control, and analog instrumentation associated with the operation of Reactor Protection, Engineered Safeguards, Reactor Shutdown, and Residual Heat Removal Systems. Credible events include, but are not limited to, the effects of short circuits, pipe rupture, missiles, etc.

General

1. Cables of redundant or backup circuits are run in separate conduits, cable trays, ducts, penetrations, etc.

2. Control and instrumentation cables are not placed in trays with cables operating above 250 V.

3. Low level instrumentation cables are not routed in cable trays containing power or control cables unless a barrier is provided. Instrumentation cables are shielded.

4. Cables are clearly identified at the terminations as being safety-related and to what separation group they belong.

Specific Systems

1. Reactor Trip System

   a. Separate routing is maintained for the four basic protection channel analog sensing signals, bistable output signals, and power supplies for such systems.

Low-Low Steam Generator Water Level Trip

The purpose of this trip is to prevent a loss of the reactor's heat sink. The trip is actuated on two-out-of-the-three low-low water level signals in any steam generator.

7.2.2.6 Reactor Coolant Flow Measurement

Elbow taps are used on each of the four loops in the Primary Coolant System as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap read-out has been well established by the following equation: $\Delta P/\Delta P_0 = (\omega/\omega_0)^2$, where ΔP_0 is the referenced pressure differential with the corresponding referenced flow rate $\omega 0$ and ΔP is the pressure differential with the corresponding referenced flow rate ω. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ± 10 percent and field results have shown the repeatability of the trip point to be within ± 1 percent. The analysis of the loss of flow transient presented in Section 15 assumes instrumentation error of ± 3 percent.

7.2.3 System Evaluation

7.2.3.1 Reactor Protection System and Departure from Nucleate Boiling

The following is a description of how the Reactor Protection System prevents departure from nucleate boiling (DNB).

The plant variables affecting the DNBR are:

1. Thermal power
2. Coolant flow
3. Coolant temperature
4. Coolant pressure
5. Core power distribution

Figure 7.2-1 illustrates the core limits for which DNBR for the hottest fuel rod is 1.3 and shows the overpower and overtemperature ΔT reactor trips locus as a function of Tavg and pressure. This illustration is derived from the inlet temperature versus power relationships.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However for all cases in which the calculated DNBR approaches 1.3, a reactor trip on overpower and/or overtemperature ΔT would also be actuated.

1. Safety Injection

2. Containment Isolation Phase A

3. Containment Isolation Phase B

4. Containment Spray

* 5. Containment Ventilation Isolation

6. Main Steam Line Isolation

7. Main Feedwater Line Isolation

8. Safeguards Equipment Control (one for each diesel generator unit)

The output of the initiation circuits each consists of a master relay which drives slave relays for contact multiplication. The logic, master, and slave relays are mounted in cabinets designated Train A and Train B, respectively, for the redundant counterparts. The slave relay circuits operate some circuit breakers, motor-operated valves and solenoid-operated valves.

* NOTE: UNIT 1 ONLY - When Unit 1 is in mode 5 or 6 and the alternate string of relays is active, the initiating relays (RMS) drive the slave relays directly. The logic circuit and master relay are bypassed.

Actuator Testing

After testing of the initiation circuits in the SSPS and SEC has been accomplished, the SSPS master relays can be reset for testing of the slave relays and the devices controlled by their contacts. By operation of these relays one at a time, all breakers and valves that can be operated online are tested.

Breakers and valves are assigned to the slave relays such that no undesired effect on plant operation can occur. Controls mounted in a Solid State Protection Test Panel are used for actuator testing. Separate panels are used for the A and B Trains. A four-position selector switch permitting rotation in one direction

only is used to test all SSPS output relays. Turning the switch to the first-position blocks those outputs which cannot be tested with the plant at power. This blocking is accomplished by latch-type test relays in the test panel. For those outputs where blocking is not required, this position is not used.

When the switch is moved to the second position, the output relay is activated. For those circuits with no blocking, the field devices function and are tested. For those circuits that are blocked, the test relay places a built-in "press-to-test" indicator light in series with the field device. Due to the low current, the field device does not operate. For normally closed output relay contacts, the test relay switches a bypass contact around the output relay contact. Current flow is determined by reading the voltage drop across small resistors in series with the normal and bypass contacts (maximum drop = 1 V).

Position 3 resets the output relay. The test lights or resistors are used to verify contact resetting. Final Position 4 resets the test relay. Again, the test lights or resistors verify that the test relay has reset. Whenever a test switch is out of Position 4 or a test relay is latched, an SSPS test alarm is activated in the Control Room.

The method of using a four-position test switch and lights or resistors for verifying field device continuity permits testing without activating the field device and verifies that the system has been reset and is in the same state as before testing. Depressing the test light lens holder breaks the normal circuit and makes up a test circuit such that the lamp can be checked instantly.

Administratively, only one test switch is operated at a time so only one SSPS output relay is tested.

During output testing, close communication between the main Control Room operator and the man at the test panel is maintained.

Prior to operating a slave relay, the operator in the main Control Room assures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has actuated a slave relay the main Control Room operator observes that all equipment has operated properly. Prepared check lists are used to verify proper operation and keep a permanent record of tests. By means of the procedure outlined above, all equipment actuated by Engineered Safeguard System initiation circuits (with the following list of exceptions) is operated by the test circuitry:

1. Feedwater Isolation Valves

2. Main Steam Isolation Valves

3. Control Air Isolation Valves

4. Turbine Trips

5. Steam Generator Feedwater Pump Turbine Trip

6. Steam Generator Feedwater Pump Stop Valves

7. Reactor Coolant Pump Trip

8. Auxiliary Feedwater Pumps

9. Generator Trip

10. Safety Injection System Valves ISJ1, 1SJ2, 1SJ4, 1SJ5, 1SJI2, 1SJ13

11. Chemical and Volume Control System Valves 1CV40, ICV41, 1CV68, 1CV69, 1CV116, 1CV284, ICV7

12. Reactor Coolant Pump Seal and Thermal Barrier Cooling Valves 1CC117, 1CC118, 1CC131, 1CC136, 1CC187, 1CC190

13. Unit 1 only - containment ventilation isolation when in mode 5 or 6 and the alternate relay string is active

The method described provides capability for checking from the process signal to the logic cabinets and from there to the individual field equipment including all field cabling actually used in the circuitry. For those devices whose operation could have an effect on plant stability, the procedure provides for checking from the process signal to the logic rack and continuity determination for output cables and field devices; however, the actuated equipment will be manually initiated as plant conditions permit.

The SEC units have the following test capability during power operation:

1. Check the operational capability of each bus undervoltage sensor and its input to the logic.

2. Check the operational capability of the LOCA signal, "S", from the SSPS logics.

3. Check that the logic combinations of input signals result in proper operation of the various functions, including automatic load sequencing, without actuation of any motors and a verification of the timed loading sequence.

4. Check the output relay capability to actuate the driven equipment.

The SEC units can also be checked for complete system operability from sensor to actuated equipment during plant shutdowns.

Reactor Trip System and ESF actuation system response time tests are required by and will be performed in accordance with the Technical Specifications.

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recirculation phase of a LOCA. The interlocks also serve to prevent unacceptable system lineups during normal plant operations. All of the interlocks use redundant devices to prevent single failures from either defeating the ECCS safety function, or the operational restrictions during normal power operation. In addition to the interlock circuitry, some of the valves are provided with control "power lockout" to meet other criteria and are described below along with an assessment of the effects of failures in the circuits.

Valves 1CV40 and 1CV41

These valves are located in the normal suction line to the charging pumps. The closing of these valves requires opening of either 1SJ1 or 1SJ2 (charging pump suction lines from the RWST) to assure that the charging pumps do not lose suction. The normal operation of the interlocks requires 1SJ1 or 1SJ2 to be fully open prior to initiating closure of the 1CV40 and 1CV41 valves. If either interlock were to fail in the direction allowing premature closure of 1CV40 or 1CV41 during a LOCA, suction to charging pumps would not be lost since 1SJ1 and 1SJ2 would be opening at the same time. This simultaneous operation of all four valves occurs since "S" signals from the plant Protection System would be transmitted to the valve control circuits simultaneously. The devices used to develop the interlock circuits are redundant. If either interlock were to fail in the direction which would prevent closure of the 1CV40 or 1CV41 valves, the redundant interlock would function to close the valves.

Valves 11RH4 and 12RH4

These valves are located in the suction lines to the No. 11 and 12 RHR pumps, respectively. The opening of each valve is enabled by the closed condition of its respective containment sump isolation valve (11SJ44 interlocks 11RH4 and 12SJ44 interlocks 12RH4). The normal status of 11RH4 and 12RH4 is "open" and ready for the injection phase of a LOCA. The interlocks are arranged on a "Train" basis so that no possible interconnection of the interlocks can occur. A failure of either interlock would affect only the opening circuit of the RH4 valve associated with that interlock. The required safety function of the RH4 valves is to be closed for Unit 1 and closed after the SJ44 valves are full open for Unit 2 when initiating the recirculation phase of a LOCA. The closure of an RH4 valve cannot be defeated by any failure in the interlocking circuitry (i.e., an opening permissive from the SJ44 valve interlock would not cause automatic opening of RH4 nor would it prevent closure of RH4).

Valves 11SJ44 and 12SJ44

Unit 1 and 2 manual mode:

These are the containment sump valves which provide suction to the RHR pumps during the recirculation phase of a LOCA. The opening of each valve is enabled by the closure of its respective RH4 valve. The normal status of these valves is "closed" with control power "locked out" in the Control Room. Unit 2 control power "locked out" feature was removed to facilitate automatic opening of the sump valves upon receipt of a switchover sequence signal.

The purpose of the interlock is to assure that spurious opening of the valve will not result in emptying the RWST into the containment sump. The interlocks are fully independent on a "Train" basis so that failures could affect only one RHR pumping path. The required safety function of these valves is to open when initiating recirculation after the RH4 valves have been closed.

A failure of the interlock in a manner tending to prematurely open an SJ44 valve would have no consequence since a valve open position must be selected by an administratively controlled SJ44 hand switch. A failure of the interlock in a manner which prevents opening the sump valve is acceptable since the other pumping path would not be affected by this interlock failure.

Unit 2 semi-automatic mode:

When the semi-automatic mod is selected for Unit 2 the containment sump valve opens when a RWST low level occurs, bypassing the closure of the RH4 valve. The RH4 valves will remain open during opening of SJ44 ensuring RHR pump suction at all times. Once the SJ44 valve is fully open its respective RH4 valve automatically closes, fulfilling the interlock purpose of not emptying the RWST into the containment sump. The semi-automatic mode is fully independent on a "Train" basis so that failures could affect only one RHR pumping path.

The required safety function of these valves is to open when initiating recirculation and to provide closure permissive to the RH4 valves.

A failure of the interlock in a manner tending to prematurely open an SJ44 valve would have no consequence since two out of four RWST low level logic signals must also occur. A failure of the interlock in a manner which prevents opening the sump valve is acceptable since the other pumping path would not be affected by this interlock failure.

Valves 1SJ67 and 1SJ68

These are the safety injection pump miniflow line valves which allow flow back to the RWST. The valves are both normally open

with the control power "locked out" in the main Control Room to assure that the safety injection pumps have a flow path until RCS pressure falls below the shutoff head of the pumps. These valves are to be closed when transferring to the recirculation phase of a LOCA. The opening of either valve is enabled by the "closed" condition of valves 11SJ45 and 12SJ45. The closing of these valves is not interlocked.

A failure of the interlock circuitry tending to open the valve would have no consequence because the normal position of the valve is open, and it also has control power "locked out." The interlock circuitry could not fail in a manner which would automatically open the valve or prevent its closure. If the interlock were to fail subsequent to the valve's being closed for recirculation, only one of the valves could be affected by the failure. The valve affected in this case would not open unless the operator erroneously initiated an "open" signal from the main control console. Even if this were to occur, the redundant valve would remain closed.

Valves 11CS36 and 12CS36

These valves are opened in the recirculation phase of a LOCA to provide flow to the containment spray headers from the RHR system. The normal position of the valve is "closed" and opening requires the opening of its associated containment sump valve (11SJ44 interlocks 11CS36 and 12SJ44 interlocks 12CS36) and the closure of either 1RH1 or 1RH2 (the normal RHR cooldown path from the RCS). The devices used to develop the interlocks are redundant so that any interlock failure would affect only one of the CS36 valves.

Interlock failures tending to prevent opening of the valve can affect only one pumping path; the other path would provide the safety function. Interlock failures which would tend to open a valve prematurely are acceptable since such failures alone are not sufficient to open the valves (operator action is required in addition to fulfilling the interlock requirements).

7.6.3.2 System Design and Operation

The POPS is a two-train system which uses separate and independent pressure transmitters to open two pressurizer relief valves if RCS pressure exceeds a preset value of 375 psi. This automatic action takes place provided the system has been armed by placing two keylocked pushbuttons in the "ON" position. The system is required to be armed whenever the RCS is below 312°F.

Each relief valve is actuated by its own logic output relay, which is energized by a bistable device. The bistable is energized if RCS pressure exceeds the setpoint. Existing pressure sensors are used to develop the signal for valve actuation. These are the same sensors which provide the open permissive interlock function of the RHR System.

The operation of the POPS is governed by two administratively controlled, keylocked pushbuttons which perform three functions. When the RCS temperature is less than 312°F, the system is armed by depressing the "ON" pushbutton for each POPS train. This action opens the motor-operated valves upstream of the relief valves and provides an alarm permissive to indicate that the POPS is armed should temperature increase above 312°F. In this mode of operation, the relief valve will automatically open if RCS pressure exceeds 375 psi. Actuation of the relief valve is alarmed in the Control Room.

When RCS temperature is above 312°F, the "OFF" pushbutton for each POPS train is depressed. This action removes the opening permissive from the relief valve, removes the opening signal from its associated motor-operated valve, and provides an alarm input to indicate that the system is disarmed should RCS temperature fall below 312°F.

When POPS is armed and in the AUTO mode, if either relief valve is opened by POPS, it will remain open until the system pressure falls below 375 psi.

A testing provision in the POPS circuitry allows for test opening of the relief valves prior to use of the system below 312°F. The "TEST" pushbutton, when depressed, will operate the relief valve provided that the associated motor-operated valve is closed. Other portions of the POPS can be tested in a manner similar to other protection system functions. The existing power operated relief valves (PORVs) are utilized for overpressure protection at low temperature in Units 1 and 2.

7.6.3.3 Design Evaluation

The POPS is designed as a "protection grade" system in accordance with the applicable portions of IEEE Standard 289-1971. The use of proven devices provides assurance that the system is compatible with other Protection System equipment. The use of administrative controls to arm the POPS is considered acceptable due to the expected infrequent need for overpressure protection at low temperature.

The POPS relief valves protect the RCS from pressure transients which could exceed the limits of Appendix G to 10CFR50 when one or more RCS cold leg temperature is at or below 312°F. Either POPS has adequate relieving capacity to protect the RCS from overpressurization as a result of the limiting heat input or mass input cases: (1) the start of an idle Reactor Coolant Pump with the secondary water temperature of the steam generator less than or equal to 50°F above RCS cold leg temperature or (2) the start of an Intermediate Head Safety Injection pump and its injection into a water solid RCS, or the start of a High Head Safety Injection pump in conjunction with a running Positive Displacement charging pump and injection into a water solid RCS. The resultant limiting RCS peak pressure has been calculated to be 452 psig (Reference 1). A number of provisions for prevention of pressure transients below P-7 (when the RCS temperature is below 312°F) presently exists in the Technical Specifications.

Unit 1 with Model-F steam generators was evaluated for the adequacy of the POPS function. The POPS function was evaluated analytically (Reference 2), specifically for Unit 1 and was found acceptable.

In order to cause an unwanted relief valve opening at normal operating pressures, an operator would have to erroneously arm the POPS system. This would require bypassing the administrative control of the key associated with the keylocked pushbutton

station. Another potential way to initiate a relief would be an unlikely short-circuit of a relay contact in the relief valve control circuit. This latter case, however, is also true of the previous circuitry for the relief valves.

Spurious opening of the relief valve at pressures below normal operations pressure could be caused by an unlikely failure of a pressure transmitter in the "high" direction. Such valve openings would result in a "low pressure" coolant inventory reduction similar to that associated with a "true" signal for relief valve operation. This type of incident could be readily terminated by the operator and poses no threat to the safety of the plant.

The effects of various failures have been considered in the POPS design. These failures included "loss of station power." Failures within the POPS cannot cause a loss of protective function due to the dual train design, and failures capable of causing an overpressurization cannot cause failures within the POPS or prevent operation of the system.

The "loss of air" situation is accounted for by provision of an air accumulator for each relief valve. The accumulators are sized to provide control air for up to 100 cycles of valve opening and closing. The accumulators are designed to seismic Category I requirements. The air accumulators are provided with an alarm for low air pressure. The accumulator design precludes a total loss of control air to the relief valves.

A "loss of station power" will have no effect on the POPS since the protection logic power is provided by inverters, and control power for the relief valves originates at the batteries.

7.6.4 Feedwater Pump Turbine Trips

There are two steam generator feedpumps and turbines. Each has its own trip sensing scheme which actuates a turbine trip for any of the following conditions:

1. Low feedpump suction pressure

2. High turbine exhaust temperature

3. Loss of vacuum at turbine exhaust

4. Excessive thrust bearing wear

5. Low lube oil pressure

6. Low oil reservoir level

7. Over speed trip-electrical sensor and detector

8. Over speed trip-mechanical (internal to turbine)

9. Safety injection or high-high level in any steam generator

10. Manual trip lever at turbine

11. Remote manual trip switch

12. Low HPU Control Oil Pressure

Automatic trip of either feedwater pump turbine will activate a separate audible and visual alarm in the Control Room.

7.6.5 References for Section 7.6

1. S-C-R200-MDM-0042, Rev. 1, RCS Overpressurization for Salem Units 1 & 2

2. FTI Doc. No. 77-1258763-00, Replacement Steam Generator Report and Safety Evaluation for Public Service Electric & Gas Company, Salem Unit One, 1997.

A simplified block diagram of the Reactor Control System is shown on Figure 7.7-1. The Reactor Control System controls the reactor coolant average temperature by regulation of control rod bank position. The system is capable of restoring reactor coolant average temperature to the programmed value following a change in load. The programmed coolant average temperature increases linearly from zero power to the full power condition.

The Reactor Control System will also initially compensate for reactivity changes caused by fuel depletion and/or xenon transients. Long-term compensation for these two effects is periodically made by adjustment of the boron concentration to return the control rod bank to its normal operating range.

The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. The error between the programmed average temperature and the highest of the measured average temperatures from each of the reactor coolant loops constitutes the primary control signal as shown on Figure 7.7-1. An additional control input signal is derived from the reactor power vs. turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transients peaks. From these input signals, the rod direction command signals are derived. The rod speed command signal varies over the corresponding range of 3.75 to 45 inches per minute depending on the magnitude and the rate of change of the input signals. The rod direction command signal is determined by the positive or negative value of the temperature difference signal. The rod speed and rod direction command signals are fed to the Rod Control System.

7.7.2.1 Rod Cluster Control Assembly Arrangements

There are 53 RCCAs divided into four shutdown banks of 24 RCCAs and four control banks of 29 RCCAs. The control banks are the only rods that can be manipulated under automatic control. The control rods are divided into groups to obtain smaller incremental

reactivity changes per step. All RCCAs in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

7.7.2.2 Rod Control

For a complete description of rod control and position indication systems, see References 1, 2 and 3.

7.7.2.2.1 Control Bank Rod Insertion Monitor

The purpose of the control bank rod insertion monitor is to give warning to the operator of a decrease in shutdown margin. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased with increasing power. One parameter which is proportional to power is used an input to the insertion monitor. This is the ΔT between the hot leg and the cold leg, which is a direct function of reactor power. The rod insertion monitor uses this parameter for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{auct}$$

where:

Z_{LL} = maximum permissible insertion limit for affected control bank

$(\Delta T)_{auct}$ = highest ΔT for all four loops

A, C = constants chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations

The Overhead Annunciator System is a high speed distributed data acquisition and display system. Non-redundant input scanners collect alarm contact state data for redundant Sequential Events Recorders (SER). The SER's provide alarm data to redundant distributed logic channels, the output of which is diode auctioneered to drive the window boxes.

All field inputs are optically coupled to scanner electronics that can read 64 inputs per scanner. When an input change of state is detected, the point address, real time, and alarm state are stored in a buffer in the scanner. The scanner is polled by the SER and transfers alarm status to the SER. The SER stores this event data in chronological order in a circular historical buffer. Normal configuration causes each alarm point to be displayed on the system console CRT, the appropriate window box, printed on the hard copy printer, and placed in the historical buffer in the local PC. If the primary controller fails due to a processor lockup (processor halts) or Port 4 failure, the primary watchdog timer circuit will switch to the backup controller.

A local PC runs the Remote Configuration Workstation (RCW) software. The RCW allows the SER to be queried for various reports and to check for errors in the system. Password entry and RCW/SER switch selection provides access for reprogramming alarms.

Periodic internal self tests are run by the SER. One test places all inputs at the scanner level in an alarm state and verifies that all inputs are passed to the SER. The SER then removes all the inputs from the alarm state and verifies that all inputs returned to their prior state. Any point not responding correctly will be printed as a faulty point. This test can also be initiated manually via the Functional Test switch located on the operator panel in annunicator cabinet 115(F). Operation of this test function does not affect the normal operation of the system.

An independent Annunciator Verification System continuously tests Overhead Annunciator System alarm processing by inputting simulated alarm stimuli through two of the scanners. These signals are then processed through the Sequential Events Recorder, and sent through the redundant chains of distributed logic controllers. Depending on the response of the two distributed logic controller trains to the stimulus, the Annunciator Verification System determines whether the annunciator system is functioning. If failures are detected, the Annunciator Verification System inputs an annunciator system trouble alarm to the Overhead Annunciator System and to an independent indicator lamp/console group alarm. The Annunciator Verification System also provides a separate trouble alarm for loss of power or self-diagnostics faults.

The system is powered by two separate 115 VAC, 60Hz supplies. Loss of either of the 115 VAC power supplies will initiate a loss of power alarm on the OHA, the plant process computer, and on a console indicator lamp/console group alarm independent of the OHA system on the control console. Redundant power supplies are provided for the field contact power, the scanners, the SER, and the distributed logic channels (including the associated window box lamps). The output of each power supply is also monitored to alarm on loss of potential in the same manner as the 115 VAC supplies.

The remotely located annunciator logic cabinets are connected by plug-in cables to the overhead display units. A test switch is also provided on the control console to test the window box lamps for operability. Operation of the test function does not affect the normal operation of the system.

System input ground detection is provided. A ground detected on an input will alarm on the OHA and on the plant process computer. The system also has a logic failure output which provides an input to the OHA and to an indicator lamp/console group alarm independent of the OHA system on the control console when certain hardware failures or communications errors occur.

The Auxiliary Alarm System (Auxiliary Annunciator System)

Each Salem Unit has an independent Auxiliary Annunciator System (AAS). The AAS is a sequential data operations recorder system used primarily for alarming and recording the loss of control circuits' potential and the off-normal position of valves. Each system consists of four (4) remote panels (133, 134, 33 and 34) containing all the input terminals, input logic, sequential memory, software, relays, power supplies, local/backup printer, system controls, and associated hardware to output sequential alarm conditions to a main printer in the Control Room. The Unit 1 AAS monitors Unit 1 parameters and provides alarm data at the Unit 1 Control Room. The Unit 2 AAS monitors Unit 2 parameters and provides corresponding alarm data to the Unit 2 Control Room.

Each Unit's system has over 700 active inputs. Each input is adequately isolated from the field at the point of the system. The system applies a field contact wetting voltage to the field circuits/alarm points and monitors the field contacts for a change in state to initiate/clear an alarm. On a contact change of state, the "contact state" and legend is printed on the main printer with an Overhead alarm "Annunciator System Printer printing."

Each system is powered two 120 VAC power sources. The AAS system can be configured to monitor normally open (NO) and/or normally closed (NC) contact conditions. The system configuration is protected by password to ensure control of database programs. The AAS monitors its system performance and provide notification of internal failures (system faults or system alerts), indicating a deficiency in system operations.

The AAS provides outputs to the Unit 1/Unit 2 Overhead Annunciator (OHA) monitoring system performance. Operator controls (pushbuttons, etc.) for system operation are provided in control room panel 1RP9 (2RP9) and AAS panel 133-1 (134-2).

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Control Console Alarm System

To facilitate operation of the plant, certain alarms are located on pushbutton control stations on the control console. These alarms are located to facilitate immediate corrective action and are actuated by either the Process Control Systems or the plant motor controls.

An alarm signal causes a back-lighted pushbutton to flash and the console audible alarm to sound until acknowledged by the operator.

Acknowledgement of an alarm condition causes the audible signals to be silenced and the alarm pushbutton to remain lit. When the alarm condition is cleared, the console audible ring-back signal sounds and the back-lighted pushbutton flashes again. Acknowledgement silences the audible signal and turns off the back-lighted pushbutton.

To facilitate the location of any pushbutton in alarm, the control console is divided into six sections, referred to as Console Alarm Groups. Each group or console section has a bull's eye indication light at the top to direct the operator's attention to that specific section of the control console containing the pushbutton

in alarm. One cabinet contains the electronics, power supplies and ground detection circuitry for the Console Group Alarm system. The Console Group Alarm system has six outputs to actuate each individual alarm group indicating light and four outputs to sound the alarm and ringback horns. Alarm horns sound a two step warble until silenced or acknowledge. Ringback horns sound a steady tone for two seconds if not silenced by the Operator.

The Process Control Systems provide alarms via four separate and independent alarm interface cabinets, one per process control group, each containing all the necessary input terminals, alarm logic, power supplies, and hardware to actuate the associated console alarms. The alarm cabinets are connected to the pushbutton stations via plug-in cables.

Each alarm cabinet is powered by two 115 V ac, 60 Hz feeds, which feed redundant dc power supplies. The outputs of both power supplies are diode auctioneered to a common bus. Each ac feed and dc potential is monitored and will actuate an alarm on the auxiliary annunciator system upon loss of voltage.

The alarm logic is entirely solid-state designed for increased reliability. Each alarm point can be actuated from either a normally closed initiating contact or by the application or removal of 115 V ac or 125 V dc. A contact change of state or change in voltage level indicates an alarm condition until it returns to its normal state. Alarm contacts are monitored by internally supplied 125 V dc.

The plant Motor Control Systems provide for numerous alarms from various plant systems. These alarms are initiated by field contacts which are monitored by the internal relay logic of the system to actuate the associated pushbutton alarm. These alarms are either of the ring-back type as previously described or of the non-ring-back type.

This system is supplied from 115 V ac, 125 V dc and 28 V dc sources. There are no internal power supplies. Each 28 V dc control circuit is protected by the use of independent breakers.

readily accessible. Portable fire extinguishers and breathing apparatus are provided. Detectors sensitive to smoke and combustion are installed in the Control Room, control console, ventilation plenum and throughout the Relay and Control Equipment Rooms. Fire detection alarms are provided in the Control Room with indication of the detector zone actuated. Further description of the fire protection provisions is given in Section 9.5.

The probability of the Control Room becoming inaccessible as a result of any cause is considered extremely small. If the operator must leave the Control Room, however, operating procedures require that he trip the reactor and turbine generator prior to leaving, thus ensuring control at the Hot Shutdown Control Stations. If necessary, the required trips can be accomplished at locations outside the Control Room.

7.7.3.7.2 Control Room Evaluation

The Control Room is designed to provide the operator with the controls, indications and alarms necessary to control the unit during normal or abnormal conditions. It is also designed for continuous occupancy, but provisions are made to attain and maintain hot shutdown from outside the control room.

7.7.3.8 Secondary System Design Evaluation

All equipment is designed with highly reliable components. Maximum use is made of solid state components in the electronic instruments; spring loaded diaphragm control valves are employed to fail safe on loss of air or power.

All instrumentation and control, where possible, is installed outside of the containment structure and in locations accessible for inspection and maintenance. Automatic control instruments in

selected systems are provided with backup manual control. Alarms are provided to warn of abnormal conditions.

7.7.4 References for Section 7.7

1. Blanchard, A. and Katz, D.N., "Solid State Rod Control System - Full Length," WCAP-9012-L (Proprietary), January 1970 and WCAP-7778 (Non-Proprietary).

2. T. Baker, B. Cassidy, J. Freeland, S. Fowler "Rod Control System Evaluation Program" June 7, 1994; WCAP-13864 Rev. 1.

3. Blanchard, A., "Rod Position Monitoring," WCAP-7571, March 1971.

cable trays. In addition, all wireways containing safety-related cables are distinctly identified as such.

8.1.4.2.4 Separation In-Plant

The routing of control, instrumentation, and power cables is such as to minimize their vulnerability to damage. Power and control cables are distributed from the switchgear and control areas by means of rigid metal conduits or ladder type cable trays.

Three separate trays are provided for 4160 V, 460 V, and 230 V power, control, and instrumentation cables. The 4160 V power cables are limited to a single layer; 460 V power cables are limited to two layers; and 230 V power, control, and instrumentation trays are not filled above the side rails.

Four independent protection channels, A, B, C, and D are provided. In general, the design criteria is a minimum vertical and horizontal spacing between redundant trays of 18 inches and 12 inches, respectively, with additional design conservatism as indicated below. Vertical tiers and crossing of redundant trays are generally avoided. Dissimilar channel designated safety-related trays are color coded at crossover points. For free air cables not installed in limited hazard areas a minimum vertical and horizontal spacing between redundant cables of 18 inches and 12 inches, respectively, shall be used except as noted below.

For installations in containment where cables are routed in free air from a conduit to a cable tray that requires separation from adjacent trays, the following minimum horizontal and vertical spacing shall be used:

Control and Instrumentation Cables
1 inch horizontal
3 inches vertical

Low Voltage Power Cables Less Than or Equal to 2/0 AWG
6 inches horizontal
12 inches vertical

There are three instances in the Salem Units where 460 V power cable trays run beneath control cable trays in a vertical tier. These instances do not involve cables from different safety-related channels. The Salem tray design criteria is such that cable trays are arranged in order of ascending voltage except where it is not possible to do so. In these cases, a fire resistant barrier has been provided in the upper tray.

Extensive flame tests performed on the cables proved that the combination of cable construction and minimum spacings used is adequate to prevent propagation of fire.

Even though the tests have proved the 18-inch vertical spacing as acceptable when redundant cables are involved, an additional fire resistant blanket is provided for each tier (except bottom tier) in the Control Room, Relay Room, and all other congested areas where the vertical spacing is 18 inches or less. The blanket is a fire resistant type and will prevent propagation of fire.

In general, the ordinal arrangement of trays is higher voltage trays on top with control cable trays at the bottom.

The safety-related cables are physically separated in accordance with channel designations, A, B, C, and D; nonsafety-related cables are routed, if necessary, in trays containing safety-related cables as follows:

E with B
F with C
G with D
H with A

Where E, F, G, and H are the nonsafety-related cables

Non-safety related cables that can be connected to a non-affiliated channel of the on-site power system must be evaluated to ensure that no loss of a safety function can occur due to the lack of physical separation of cables.

The grouping of penetrations in the electrical penetration area and the selection of conductors for each penetration follows the criteria established for the separation of redundant cables and provides for the implementation of these criteria for the cables approaching and leaving the area.

Written design and installation procedures are established to assure that nonsafety-related cables only run with one safety-related channel.

8.1.4.2.5 Separation in Control Areas and Components

Limited Hazard Areas

Limited hazard areas at Salem are considered to be the Relay Rooms, Elevation 100' and Control Equipment Rooms, Elevation 122'. The required physical separation of cables in free air is designated as 1" horizontal and 3" vertical for instrumentation and control cables and 6" horizontal and 12" vertical for low voltage power cables less than 2/0 AWG.

Control Boards, Panels and Racks

The control boards, panels, and relay racks have been designed to provide independence and separation necessary to fulfill the single failure requirement of IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

Control Console

The control console is a free standing unit that is totally enclosed including a dropped floor with a steel bottom plate. All cables entering the console pass through sealing bushings installed in the steel bottom plate on 6-inch centers. Up to eight cables may pass through a numbered sealing bushing; however, only cables of the same separation designation are permitted in a single bushing. Safety-related and nonsafety-related cables may be assigned to the same bushing in accordance with the criteria stated above.

Once in the console, cables are assigned to a four-section cable lattice arrangement with supports which have a minimum center to center distance of 1 7/8 inches and are 2 inches high. Cables go through the lattice to the plug-in instruments. The lattice is assigned separation designations and is also divided horizontally into a numbered grid system. Each cable is assigned a separation designation, a bushing, and a lattice position number. Therefore, the location and path of each cable in the console is individually defined. Installed cables are fastened to the lattice supports.

The plug-in cables terminate at the rear of the console-mounted equipment. All pushbutton stations and vertical indicators plug into identical steel housings which have a rear-mounted receptacle for the plug-in cable.

The steel housings provide physical separation for adjacent pushbutton stations or indicators. There are no exposed terminations associated with the control stations and indicators.

Each pushbutton station has functions associated with one separation designation. The minimum center-to-center distance between the double barriered control station housings is 1 1/2 inches and is based on the use of low voltage controls and special teflon insulated plug-in cables. This minimum distance occurs at the entrance to plug-in modules containing terminations which are enclosed in a steel housing. From the modules, the cables are separated in the lattice system described above which provides for specific routing of the cables to the floor bushings. Redundant cables are "fanned out" from the modules to achieve a greater separation as soon as practical; however, the separation is never less than 1 1/2 inches, center to center. Safety-related wiring other than the plug-in cables is run in conduit.

The reactor trip switches' wiring is not of plug-in cable construction. Reactor trip wiring is run in conduit (using two separate paths for the two trains) from the entrance to the console up to the switches. Wiring for redundant functions is separated by using the front and rear decks of the multi-deck switch.

Each circuit in the 28-V dc Logic System is protected by circuit breakers. Current overload tests have been performed on the multi-conductor plug-in cable based upon the calculated current which would occur if the circuit protection failed to interrupt a short circuit due to failures in the pushbutton control stations. These tests showed that a fault occurring in a pushbutton control station could not cause a fire in the console space.

Within the console, color coding is used to identify the cables and connectors associated with each of the four safety-related and nonsafety-related channels.

3. Loss of the Most Critical Transmission Line

There are three 500-kV transmission outlets from Salem Generating Station, one to New Freedom Switching Station, one to Deans Switching Station, and one to the adjacent Hope Creek 500-kV switchyard.

For stability analysis purposes, a three-phase fault at Salem was simulated on each of the three 500-kV circuits. A fault on the Salem-Hope Creek 500-kV line is the most critical line fault in evaluating Salem stability. For a fault on this line the Salem units will remain stable.

System Stability Studies performed for unexpected operating conditions such as Hope Creek - Red Lion 500-kV or Salem - Deans 500-kV line having an extensive outage, have indicated that the most critical condition is the disconnection of the Salem - Deans or the Hope Creek - Red Lion 500-kV line respectively. In such a situation to maintain System Stability, the tripping of one of the Salem Units is required. The relay protection circuitry was modified to incorporate this change.

The above considerations minimize the possibility of loss of more than one offsite power source. In the event of a loss of all offsite power sources, the Engineered Safeguards Systems will be supplied from the standby ac power supply (see Section 8.3.1.5).

Emergency lighting is provided throughout various areas of the plant where operator action may be required. In addition, 8-hour battery pack lights have been provided in selected areas of the plant as part of the fire protection program. Sufficient lighting exists for postulated loss of ac power events. No action is required for these lights to be operational.

The new trip setpoint of 95.1 percent is based upon the results of detailed analyses of the Salem Generating Station electrical distribution system transient response characteristics. Those analyses indicate that, at the PSE&G bulk power system voltage minimum expected value and for a LOCA on one Salem unit and a concurrent orderly shutdown of the other unit, vital bus voltage will recover to a worst-case value of ≈97 percent. The minimum allowable trip value and trip setpoint are derived using the 90-percent minimum motor terminal voltage requirement as a starting point and then applying appropriate allowances required by Regulatory Guide 1.105.

Group bus undervoltage protection (68 percent of nominal) will automatically trip the reactor coolant and condensate pump 4-kV breakers upon sensing an undervoltage (i.e., loss of voltage) condition on its respective 4-kV group bus (1E, 1F, 1G, and 1H) using 1/1 logic taken once.

8.3.1.3 460- and 230-Volt Systems

The 460-V Auxiliary System feeds most motors from 20 to 300 hp. The 230-V System feeds smaller loads and, for convenience of operation, a few motors larger than 15 hp. The 4160-V System feeds the 460-V and 230-V systems via 4160-460-V and 4160-240-V transformers.

The 460-V and 230-V Vital Bus Systems are divided into three bus sections which correlate to their respective 4160-V vital buses.

8.3.1.4 115-V ac Instrumentation Power

Four 12-kVA 115-V ac vital instrument buses (1/2 A,B,C & D) receive power from individual Uninterruptible Power Supplies (UPS) to form redundant channels for reactor control and protection instrumentation and safety-related equipment. Each vital instrument bus UPS's Rectifier receives normal source, vital 230-V ac power, converts (rectifies ac/dc) it to dc power, and then converts (inverts dc/ac) it to ac power. In the event of a 230-V ac power loss or an UPS's Rectifier malfunction, 125-V dc vital station battery power will automatically supply power to the UPS's Inverter, via the UPS's actioneering circuit, to maintain uninterruptible ac output power.

Each UPS also contains a 12-kVA ac Line Regulator and Static Switch that receives alternate source, vital 230-V ac power from the same normal source vital 230-V ac bus. In the event of an UPS's Inverter malfunction, the Static Switch senses a loss of Inverter output voltage and automatically fast transfers the associated vital instrument bus loads to the ac Line Regulator 115-V ac output. When the UPS's Inverter voltage returns to normal, the Static Switch will automatically return the associated vital instrument bus loads to the Inverter output.

Table 8.3-1 depicts channel designations for each vital instrument bus power feed. The 115-V ac Control Power System for Units 1 and 2 is illustrated on Figure 8.3-5.

2. Controls in the Control Room:

Diesel generator voltage, frequency, watts, amps.

3. Alarms local to the diesel generator:

Cooling water temperature low
Cooling water temperature high
Jacket water temperature high
Jacket water heater failure
Lube oil temperature high
Lube oil heater failure
Fuel oil day tank level low
Expansion tank level high
Crankcase level high/low
Engine lube oil header pressure low
Fail to start (overcrank)
Diesel generator tripped
Generator negative phase sequence
Fuel oil day tank level high
Pre-lube pump failure
Crankcase blower failure
Exciter regulator on manual control
Diesel generator locked out (for maintenance)
DC control voltage failure-a single alarm to include the following:

Loss of dc power to the engine control
Loss of dc power to the generator field
Loss of dc power to the unit trip circuit
Loss of dc power to the local alarm system

Air receiver No. 1 pressure low
Air receiver No. 2 pressure low
Generator breaker trip
Generator field ground

Expansion tank level low
Generator overspeed
Generator overvoltage
Generator loss of PT secondary voltage
Generator ground fault
Turbo air receivers low pressure

4. Alarms in the Control Room:

Diesel generator trouble (a common alarm which will be actuated by the operation of any of the above local alarms).

Diesel generator urgent trouble-a single alarm to include the following:

Jacket water temperature high
Lube oil temperature high
Engine lube oil header pressure low
Air receiver pressure low
Pre-lube pump failure
Generator ground fault
Turbo air receivers low pressure

Fuel oil day tank level trouble (a common alarm for all three unit day tanks).

Loss of dc power to the engine control, generator field, trip circuits.

Diesel generator in Local-Manual control mode, failure to start, emergency trip, locked out.

Generator breaker spring charger failure, breaker trip.

respectively. Safety-related loads are identified by the use of the symbols A, B, C, D on the feeders. Battery load profiles are shown in Tables 8.3-5 and 8.3-6.

As shown on Figure 8.3-7, three 125-V batteries are provided for each unit to supply an independent source of control power for each of the three 4160-V and 460-V vital buses and for the 125-V distribution cabinets. A backup source of control power for each of these buses is provided via manually operated, mechanically interlocked breakers under administrative control.

The station dc systems provide a continuous source of power for operation of circuit breakers, valve controls, inverters, etc. No initiation or control is required to connect the batteries to the dc buses.

Two separate non-safety related 125-V dc batteries have been provided to serve the 4160 V CW switchgear, 13 kV south bus section breakers, SCADA systems and portions of switchgear relaying systems.

8.3.2.2 Station Batteries

The Station Battery System includes one non-vital 250-V, three vital 125-V, and two vital 28-V batteries, static battery chargers for each battery, and a ground detection system and undervoltage alarm relay for each bus.

The batteries are mounted on corrosion-resistant, seismically designed steel racks in separately ventilated and isolated areas. The 250-V, 125-V, and 28-V batteries are rated 1326, 2320, and 800 ampere hours, respectively, at the 8-hour rate of discharge.

Each charger maintains a floating charge on its associated battery, and is capable of supplying the required equalizing charge when necessary. Each 125-V and 28-V Battery System (one battery, two chargers, and one switchgear unit) has a ground detection system, undervoltage alarm relay, and dc voltmeters and ammeters. Each 28-VDC charger is equipped with an ac failure relay. Loss of ac input and/or dc output is annunciated in the Control Room. Each Unit 1 125-VDC battery charger is equipped with a loss of AC voltage alarm. Each Unit 2 125-VDC charger is equipped with a summary trouble alarm which indicates AC Power Failure, High Voltage Shutdown, No Charge and High/Low Voltage. Alarms from both Unit 1 and Unit 2 battery chargers are printed in the Control Room.

Each battery is connected to its associated switchgear through a disconnect switch and protective fuses. The dc distribution switchgear consists

of metal-clad structures, each with an ungrounded main bus, and 2 pole air circuit breakers.

During normal operation, the dc load is fed from the battery chargers with the batteries floating on the system. Upon loss of dc power from a battery charger, the dc load is drawn from the batteries. The batteries are sized for 2 hours of operation after a loss of ac power, based upon the required operation of the dc emergency equipment. If all offsite power is lost, the battery chargers are energized from the emergency diesel generators and resume their function automatically.

8.3.2.3 Station Battery Monitoring

Two chargers, each capable of 100-percent normal load, are provided for each 28-V and 125-V dc battery. Each normal charging source supplies the continuous dc loads and maintains a float charge on the battery to ensure the capability of each battery to deliver its emergency dc requirements. The 28-V and 125-V chargers are fed from the vital ac buses. Each 28-V and 125-V battery is fed from two separate vital buses. One charger is under administrative control to assure that the 230-V ac buses will not become interconnected.

One 250-V dc charger is provided due to the nature of the 250-V dc loads, with a provision to tie in the other unit's 250-V charger, if needed.

Each of the 6 batteries per unit is continuously monitored in the Control Room for voltage and discharge current. Listed below are all the monitoring devices associated with each battery. A brief description of the function of each device and its location is given.

Battery Voltmeter - Monitors dc bus voltage with continuous readout in the Control Room.

Battery Load Ammeter - Monitors discharge current with continuous readout in the Control Room.

Ground Detectors - Monitors leakage from positive and negative buses to station ground with continuous readout in the Control Room. In addition, local ground detection circuit is provided adjacent to each charger for test purposes.

Undervoltage Alarm - Monitors each dc bus and alarms in the Control Room when bus voltage drops below a preset value.

Charger Voltmeter - Monitors charger output voltage at charger cabinet.

Charger Alarm - Monitors ac input to charger and alarms in the Control Room upon loss of input voltage to both 28-VDC chargers. Each Unit 1 125-VDC battery charger is equipped with a loss of AC voltage alarm. Each Unit 2 125-VDC battery charger is equipped with a charger trouble relay which provides a summary alarm in the Control Room if the energized charger experiences an AC power failure, high voltage shutdown, no charge or high/low voltage. The 250-VDC chargers also have an overvoltage alarm in the Control Room should the bus voltage rise above a preset value.

DC Distribution Cabinet Undervoltage Alarm - Each 28-V and 125-V dc distribution cabinet is provided with an undervoltage relay which monitors bus voltage and alarms in the Control Room.

Blown Fuse Alarm - Each battery fuse is monitored to alarm in the Control Room if the fuse should blow.

Protection against overcharging is provided within the charger itself which is a constant voltage-current limited device.

Surveillance requirements are set forth in the Technical Specifications.

The general cleanliness of battery, float charge, cell cracks, electrolyte leakage, ventilation equipment, cell to cell connections, etc, are periodically inspected to assure good

service and long battery life. Thus, degradation can be monitored and rectified during surveillance and testing program.

8.3.2.4 CW Switchgear Batteries

Each CW Switchgear Battery System includes one 125-V battery, two static battery chargers, ground detection and metering cabinet.

The batteries are mounted on corrosion resistant steel racks in separate ventilated and isolated areas located in the Circulating Water Switchgear Building. Each battery is rated 960 ampere-hours at the 8-hour rate of discharge.

Each charger maintains a floating charge on its associated battery, and is capable of supplying the required equalizing charge when necessary. Each battery charger provides a charger failure alarm signal to the SCADA System.

The battery is connected to its associated 125-V distribution panel through protective fuses and a manual transfer switch. The manual transfer switch allows either 125-V distribution panel to be switched to the other battery if its own battery is out of service.

During normal operation, the dc load is fed from the battery chargers with the battery floating on the system. Upon loss of AC power to the battery chargers and the P250 computer inverter, the battery can supply the full P250 inverter load of 15KVA for up to 2 hours and the remaining DC loads for up to 4 hours.

8.3.3 Containment Penetration/Conductor Overcurrent Protection

The containment penetrations/conductors are protected by deenergizing circuits which are not required for reactor operation and by ensuring the operability of primary/backup overcurrent protective devices through periodic testing of equipment/systems. The containment penetration/conductor overcurrent protection devices are listed in and controlled by Engineering Calculations Numbers ES-13.010(Q) and ES-13.005 (Q) for Salem Units 1 and 2, respectively. An integrated system functional test includes the simulated automatic actuation of circuit breakers to verify response times and trip setpoints.

SECTION 9

AUXILIARY SYSTEMS

The Auxiliary Systems are supporting systems required for safe operation and servicing of the Reactor and the Reactor Coolant System and Engineered Safeguards Systems.

9.1 FUEL STORAGE AND HANDLING

The Fuel Handling and Storage System provides a safe, effective means of storing, transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. Each unit has a completely independent Fuel Handling and Storage System. The following description is for Unit 1 with Unit 2 having an identical system.

The system is designed to minimize the possibility of mishandling or of maloperations that could cause fuel damage and potential fission product release.

9.1.1 New Fuel Storage

9.1.1.1 Design Bases

The new fuel assemblies are received and stored dry in racks in the new fuel storage area, located in the Fuel Handling Building (see Figure 9.1-1). New fuel is delivered to the reactor by lowering it into the transfer pool and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and control rods normally associated with the replacement of one-third of a core.

9.1.1.2 Safety Evaluation

The new fuel storage racks have been designed in accordance with the 1963 AISC Code. Seismic loads as well as dead load of fuel assemblies are considered in the design. The new fuel storage racks are designed so that it is impossible to insert the assemblies in other than the prescribed locations. The 21-inch nominal spacing between fuel assemblies will maintain a subcritical array even if the pool is flooded with unborated demineralized water.

Adequate shutdown margin is maintained for 17 x 17 fuel with 4.65 w/o (5) enrichment and no Integral Fuel Burnable Absorbers (IFBA) present. For consistency with the Region I (Exxon) spent fuel storage rack requirements (where new fuel must be placed before loading the core), only up to 4.25 w/o enriched 17 x 17 fuel assemblies without IFBA are allowed to be stored in the new (dry) fuel storage racks. Unirradiated fuel assemblies with enrichments greater than 4.25 w/oU-235 and less than or equal to 5.0 w/o U-235 are acceptable for storage with credit for a minimum number of IFBA pins. This minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold-down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5X), determined by the equation below:

$$N = 42.67(E - 4.25)$$

The above equation is based on a more restrictive IFBA requirement for the Region I spent fuel racks and is conservative for the new fuel racks. E in the equation above is the fresh assembly design enrichment. A potential optimum moderation condition is precluded in the new fuel storage area by the following design features.

1. The Fuel Handling Building has no fire fighting hose stations,

2. The Fuel Handling Building has no installed aqueous fire suppression systems (e.g., sprinklers, fog, or sprays),

3. New fuel is covered with a protective metal plate during storage which prevents the introduction of low density water into the fuel racks from above.

The only accessible fire fighting hoses available for use in the new fuel storage area are connected to hose stations in the auxiliary building and will be equipped with straight-stream nozzles.

9.1.2 Spent Fuel Storage

The spent fuel storage pool is the storage space for irradiated spent fuel from the reactor. This pool is not required for any plant safety-related function.

9.1.2.1 Design Bases

The Spent Fuel Pool reracking project implemented in 1994 increased the fuel storage capacity from 1170 fuel assemblies to 1632 fuel assemblies. The reracking project retained 3 existing high density Exxon Nuclear Corporation odules containing 300 cells (Region I) and added 9 new maximum density Holtec modules containing 1332 cells (Region II) with a total storage capacity of 1632 fuel assemblies. The reracking provided an additional 10 years of storage capacity, which is expected to be sufficient up to the year 2008 for Unit 1 and 2012 for Unit 2.

The spent fuel storage racks are designed and shall be maintained with:

a. A maximum Keff equivalent of 0.95 with the storage racks filled with unborated water.

b. A nominal 10.5 inch center-to-center distance between fuel assemblies stored in Region I (flux trap type) racks.

c. A nominal 9.05 inch center-to-center distance between fuel assemblies stored in Region II (non-flux trap) racks.

d. Fuel assemblies stored in Region I racks shall meet one of the following limiting conditions.

   1. Unirradiated fuel assemblies with a maximum enrichment of 4.25 w/o U-235 have unrestricted storage.

   2. Unirradiated fuel assemblies with enrichments greater than 4.25 w/o U-235 and less than or equal to 5.0 w/o U-235, that do not contain Integral Fuel Burnable Absorber (IFBA) pins, may only be stored in the peripheral cells facing the concrete wall.

   3. Unirradiated fuel assemblies with enrichments (E) greater than 4.25 w/o U-235 and less than or equal to 5.0 w/o U-235, which contain a minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold-down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5X), determined by the equation below.

$$N = 42.67\ (E-4.25)$$

4. Irradiated fuel assemblies with enrichments (E) greater than 4.25 w/o U-235 and less than or equal to 5.0 w/o, that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -26.212 + 6.1677E$$

e. Fuel assemblies stored in Region II racks shall meet one of the following limiting conditions.

1. Unirradiated fuel assemblies with a maximum enrichment of 5.0 w/o U-235 may be stored in a checkerboard pattern with intermediate cells containing only water or non-fissile bearing material.

2. Unirradiated fuel assemblies with a maximum enrichment (E) of 5.0 w/o U-235 may be stored in the central cell of any 3x3 array of cells provided the surrounding eight cells are empty or contain fuel assemblies that have attained the minimum burnup (BU) as determined by the equation below.

$$BU\ (MDW/kg\ U) = -15.48 + 17.80E - 0.7038E^2$$

In this configuration, none of the nine cells in any 3x3 array shall be common to cells in any other similar 3x3 array. Along the rack periphery, the non-fueled region is equivalent to 3 outer cells in a 3x3 array.

3. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 w/o U-235 that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -32.06 + 25.21E - 3.723E^2 + 0.3535E^3$$

4. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 w/o U-235 that have attained the minimum burnup (BU) as determined by the equation below, may be stored in a peripheral cell facing the concrete wall.

$$BU\ (MWD/kg\ U) = -25.56 + 15.14E - 0.602E^2$$

9.1.2.3 Design Evaluation

Borated water is used to fill the spent fuel storage pool at a concentration to match that used in the reactor cavity and refueling canal during refueling operations. The fuel is stored in a vertical array with sufficient center-to-center distance between assemblies to assure $k_{eff} \leq 0.95$ even if unborated water is used to fill the pool. (Based on 17 x 17 fuel with enrichment as described in Section 9.1.2.1).

The spent fuel storage pool is provided with a Spent Fuel Cooling System which is discussed in Section 9.1.3. Normally, the system maintains pool temperature below approximately 149°F.

The design of the Fuel Handling Building is such that it is physically impossible for a load greater than 5 tons to be carried over the spent fuel pool except during implementation of the rerack project. This is a result of both the physical arrangement of the Fuel Handling Building and limits on the fuel handling crane. Administrative controls prohibit loads greater than that of a fuel assembly to travel over the spent fuel pool. The maximum height at which a fuel assembly can be carried is restricted by limit switches on the crane to 15 inches over the top of the spent fuel racks. The spent fuel racks have been designed to absorb the energy released by a fuel assembly dropping from 15 inches above them for the Exxon racks and 36 inches for the Holtec racks.

During implementation of the rerack project in 1994, temporary modification was made to the crane which increased the capacity of the crane from 5 tons to 20 tons. No permanent attachment or welding to the crane was made. This temporary modification was removed at the completion of the project and the crane was brought back to it's original capacity of 5 tons.

Special procedures were also implemented to prevent the possibility of a rack under transport from impacting stored fuel. Racks were also temporarily located in the transfer pool (two for Unit 1, one for Unit 2) to reduce the amount of fuel in the Spent Fuel Pool.

The spent fuel storage pool and new fuel storage pit are outside the area over which the fuel cask may travel by design (travel restricted by a limit stop switch). The cask handling crane travels only over the truck bay, decontamination pit and fuel transfer pool, as indicated on Figure 9.1-1.

Gamma radiation is continuously monitored in the Fuel Handling Building. A high level signal is alarmed locally and is annunciated in the Control Rooms.

All fuel and waste storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and will not exceed the guidelines of 10CFR100.

A Controlled Ventilation System removes gaseous radioactivity from the atmosphere in fuel and waste treating areas of the Fuel Handling and Auxiliary Buildings and discharges it to the atmosphere via the plant vent. Radiation monitors are in continuous service in these areas to actuate high-activity alarms in the Control Rooms.

A nuclear criticality accident due to a fuel assembly misloaded in the Spent Fuel Pool has been analyzed. This relates to fuel assemblies loaded in a wrong region as specified in Section 9.1.2.1. One mislocated fuel bundle has been found to be acceptable as long as the soluble boron concentration is maintained above 600 ppm in the Spent Fuel Pool.

A nuclear criticality accident due to the installation of maximum density spent fuel storage racks has been analyzed. Reracked pool design factors that could affect the Spent Fuel Pool neutron multiplication factor have been addressed conservatively. It was concluded that the maximum Spent Fuel Pool neutron multiplication, with the addition of the maximum density racks, will not exceed the subcriticality limit of Keff less than or equal to 0.95 with unborated water.

A rack-to-rack and rack-to-wall impact during a postulated seismic event was analyzed for the spent fuel storage racks for the as-built configuration. The analysis concluded that the rack configuration does not result in rack-to-rack impact in the cellular region for either unit, or rack-to-wall impact for Unit 1 during postulated seismic events. For Unit 2, a rack-to-wall impact is predicted in one location for the DBE case. The calculated value of the impact force is very small and will not cause any damage to the fuel cells, the rack, the wall or pool liner.

9.1.3 Spent Fuel Pool Cooling System

9.1.3.1 Design Bases

The following description is for Unit 1 with Unit 2 having an identical system.

The Spent Fuel Pool Cooling System is designed to remove from the spent fuel pool the heat generated by stored spent fuel elements. The system serves the spent fuel pool which is located in the Fuel Handling Building adjacent to the Containment Building. A secondary function is to clarify and purify spent fuel pool, transfer pool, and refueling water. The system design considers the need to totally unload a reactor at the time when spent fuel is in the fuel pool.

The system design incorporates redundant active components. The system is designed with anti-siphon holes to prevent draining of the spent fuel pool below the top of the stored fuel elements.

The Spent Fuel Pool Cooling System maintains pool temperature at or below 149 degrees F, provided both SFP heat exchangers are available. If only one heat exchanger is available, pool temperature is limited to 180°F. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.2 System Description

The schematic diagram for the Spent Fuel Pool Cooling System is shown on Figures 9.1-4A and B. The Spent Fuel Pool Cooling System

consists of three subsystems: the Cooling System, the Purification System, and the Skimmer System.

Austenitic stainless steel piping is used in the Spent Fuel Pool Cooling System. All piping and components of the system are designed to the applicable codes and standards listed in Table 9.1-1.

The cooling loop consists of the spent fuel pool pumps and the spent fuel pool heat exchanger. The purification loop consists of the spent fuel pool pump, the spent fuel pool filter, the spent fuel pool demineralizer, the refueling water purification pump, and the refueling water purification filter. The skimmer loop consists of the skimmer pump, strainer, and filter.

During the heat removal operation, fuel pool water flows from the spent fuel pool to a spent fuel pool pump suction, and is pumped through the tube side of the heat exchanger, and is returned to the pool. The suction line, which is protected by a strainer, is located at an elevation 4 feet below the pool normal water level, while the return line terminates in the pool at an elevation approximately 6 feet above the top of the fuel assemblies. If the spent fuel pool pump fails, the second pump supplies 100-percent backup.

The Spent Fuel Pool Cooling System has its maximum duty during the refueling operation when the decay heat from the spent fuel is the highest.

Piping and valves are installed which allow the Units 1 and 2 heat exchangers to be cross connected. During normal plant operation, the heat exchangers operate independently to meet the cooling requirements of the individual units. However, if heat load is unusually high, both heat

exchangers may be used in parallel to minimize the temperature rise in the spent fuel pool. The cross connect also allows one heat exchanger to be used to alternatively cool the spent fuel pools in both units during times when one heat exchanger is out for maintenance.

While the heat removal operation is in process, a portion of the spent fuel pool water, 100 gpm, may be diverted through the spent fuel pool demineralizer and spent fuel pool filter to maintain spent fuel pool water clarity and purity. Transfer canal water may also be circulated through the same demineralizer and filter. This is accomplished by having the gate between the transfer pool and the spent fuel pool removed. This purification loop is sufficient for removing fission products and other contaminants which may be introduced if a leaking fuel assembly is transferred to the spent fuel pool.

The demineralizer may be isolated, by manual valves, from the heat removal portion of the Spent Fuel Pool Cooling System. By so doing, it may be used together with the refueling water purification filter to clean and purify the refueling water while spent fuel pool heat removal operations proceed. Connections are provided to the isolated loop such that the refueling water may be pumped from either the refueling water storage tank (RWST) or the refueling cavity, through the demineralizer and filter, and discharged to either the refueling cavity or the RWST.

To further assist in maintaining spent fuel pool water clarity, the water surface is cleaned by a skimmer loop. This system consists of two skimmers, a skimmer pump, a strainer and a filter. Water is removed from the surface by the skimmer, pumped through the strainer and filter, and returned to the pool surface at three locations remote to the skimmers.

Boron may be added to the pool from the Chemical and Volume Control System (CVCS). Borated water from the plant sources may be supplied from the RWST via the refueling water purification pump connection, or by placing a temporary line from the boric acid blender, located in the CVCS directly into the pool. Demineralized water is also added to the pool for makeup purposes by a connection in the recirculation return line.

The pool water may be separated from the water in the transfer pool by a sluice gate. The gate is installed so that the transfer pool may be drained for maintenance on the fuel transfer equipment. The draining is accomplished by pumping transfer pool water into the spent fuel pool with a portable pump. The excess water from the spent fuel pool is directed to a holdup tank in the CVCS or to the decontamination for temporary storage.

With the implementation of reracking in 1994 the spent fuel storage capacity in the pool was increased from 1170 fuel assemblies to 1632 fuel assemblies. The decay heat load calculation was conservatively performed in accordance with the provisions of USNRC Branch Technical Position ASB9-2, "Residual Decay Energy for Light Water Reactors for Long Term Cooling," Rev. 2, July 1981. Three discharge Cases were considered in Cycle 25, 37 years' accumulation of spent fuel:

Case 1) The reactor is shutdown and is cooled for 168 hours. Then, a batch of 88 assemblies with 1642.5 days full power operation is discharged to the pool at a rate of 7 assemblies per hour.

Case 2) Same as case 1 except instead of 88 assemblies, 193 assemblies (Full Core Offload) is discharged.

Case 3) The reactor is back to operation after a refueling shutdown in Cycle 24. Thirty days later, the reactor experiences unplanned shutdown. The full core of 193 assemblies is transferred to the pool 168 hours after the reactor shutdown. Sixty eight assemblies in the core are assumed to have 30 days full power operation and 125 assemblies are assumed to have 1642.5 days full power operation.

The results of the above cases are as follows:

Case 1) 195 hours after the reactor shutdown, the pool will experience a maximum temperature (bulk pool) of 149 degrees F, with one pump and one heat exchanger in operation.

Case 2) 205 hours after the reactor shutdown, the pool will experience a maximum temperature of 180 degrees F, with one pump and one heat exchanger in operation.

Case 3) 204 hours after the reactor shutdown, the pool will experience a maximum temperature of 180 degrees F, with one pump and one heat exchanger in operation.

In 1998, additional spent fuel pool heat removal analyses were performed. The analyses addressed potential full-core off-loads during upcoming refueling outages as well as end of plant life. These analyses concluded one pump and one heat exchanger can maintain pool temperature below 149°F under all combinations of decay time and CCW temperature except minimum decay times and very high cooling water temperatures. Under these later conditions, in vessel decay-time would be extended or parallel heat exchanger operation would be used to maintain pool temperature below 140°F. in additiona, provisions have been made for the installation of an additional heat exchanger, should this be required in the future.

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Provisions have been made for the addition of an additional heat exchanger, should this be required in the future.

Spent Fuel Pool Cooling System component design data are listed in Table 9.1-2. The following is a description of each component utilized in the Spent Fuel Cooling System.

Spent Fuel Pool Heat Exchanger

The spent fuel pool heat exchanger is of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and spent fuel pool water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

Spent Fuel Pool Pumps

The spent fuel pool pumps circulate water in the Spent Fuel Pool Cooling System. All wetted surfaces of the pumps are austenitic stainless steel, or equivalent corrosion resistant material. The pumps are operated manually from a local station.

Spent Fuel Pool Filter

The spent fuel pool filter removes particulate matter larger than 5 microns from the spent fuel pool water. The filter cartridge is of synthetic fiber and the vessel shell is austenitic stainless steel.

Spent Fuel Pool Strainer

A stainless steel strainer is located at the inlet of the spent fuel pool cooling suction line for removal of relatively large particles which might otherwise clog the spent fuel pool demineralizer.

Spent Fuel Pool Demineralizer

The demineralizer is sized to pass 100 gpm of the loop circulation flow to provide adequate purification of the fuel pool water for unrestricted access to the working area and to maintain optical clarity.

Refueling Water Purification Pump

The refueling water purification pump circulates water in a loop between the RWST and the spent fuel pool demineralizer and the refueling water purification filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

Refueling Water Purification Filter

The refueling water purification filter removes particulate matter larger than 5 microns from the refueling water purification flow.

Spent Fuel Pool Cooling System Valves

Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with spent fuel pool water are austenitic stainless steel or equivalent corrosion-resistant material.

Spent Fuel Pool Cooling System Piping

All piping in contact with spent fuel pool water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

Spent Fuel Pool Skimmers

Two spent fuel pool skimmers are provided to remove water from the surface of the spent fuel pool. The skimmer heads are manually

positioned to take water from any elevation from the water surface to 4 inches below the surface. The elevation of the skimmers' head can be manually adjusted over a total range of 2 feet.

Spent Fuel Pool Skimmer Pump

The spent fuel pool skimmer pump circulates surface water through a strainer, a filter, and returns it to the pool.

Spent Fuel Pool Skimmer Strainer

The spent fuel pool skimmer strainer is designed to remove debris from the skimmer process flow.

Spent Fuel Pool Skimmer Filter

The spent fuel pool skimmer filter is designed to remove insoluble particles which are not removed by the strainer.

9.1.3.3 Design Evaluation

The most serious failure of this system would be complete loss of water in the spent fuel pool. To protect against this possibility, the spent fuel pool cooling suction connection enters near the normal water level so that the pool cannot be gravity-drained. The cooling water return lines contain anti-siphon holes to prevent the possibility of gravity draining the pool. For beyond design basis accident mitigation, the tell-tale liner leakoff drain lines have isolation capability to maintain spent fuel pool inventory in the unlikely event that liner failure is anticipated as a result of a complete loss of spent fuel pool cooling. There are no drains or permanently connected systems to the spent fuel pool (Seismic Class I) which, in the event of failure, could cause loss of coolant from the pool that would uncover the fuel. Also, provisions have been made to supply makeup to the spent fuel pool as noted below.

Salem fuel pool cooling systems were designed with substantial reliability. Original design features included a seismic Class II piping stress analysis (upgraded to Class I in 1981), location in seismic Category I buildings, safety-related heat exchangers, a safety-related heat sink (CCW to service water), redundant pumps, and electric power supplied by independent 460 volt 1E buses (backed by emergency diesel generators). Under the original design, the system could be expected to remain functional following any design accident or natural phenomena, except a design basis earthquake (DBE). Since the system components were not seismically qualified, post-DBE functionality was not assured. In that case, if an earthquake caused a sustained loss of forced cooling with recently discharged fuel in the pool, decay heat would have been removed by pool boiling.

As a result of self-assessments performed on the fuel pool and associated structures, systems and components (SSCs) in 1995, concerns were identified that called into question the ability of these SSCs to perform their design basis functions under loss of normal fuel pool cooling conditions as a result of a design basis earthquake where the heat load in the pools could cause the pool temperature to exceed 180°F. These concerns were resolved by a seismic upgrade of the Spent Fuel Pool Cooling System to render temperatures above 180° F non-credible. The upgrade not only evaluated the capability of the system to remain functional following a seismic event, but also evaluated potential single active failures and various external hazards (such as flooding, missles, seismic-nonseismic interactions, etc.) that could result in interruption of forced cooling. The evaluation concluded pool temperature would be maintained 180°F and below under normal, abnormal, and accident conditions.

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The use of the heat-exchanger cross connect is controlled by appropriate procedures. Four manual valves, two per unit, have to be opened to cross connect the heat exchangers. Prior to placing a high heat load in a pool which would require heat exchangers in parallel to minimize the temperature transient, the heat load in the spent fuel pool to be isolated is evaluated to ensure it can tolerate a temporary interruption of cooling. Similarly, before taking one heat exchanger out of service for maintenance, the heat loads in both spent fuel pools are evaluated to verify that the remaining heat exchanger can be used in an alternating fashion to cool both spent fuel pools.

Water loss from the spent fuel pool due to the accidental opening of a sluice gate when the transfer pool is empty will not occur due to the redundancy in the sluice gates. Two sluice gates separate the spent fuel pool from the transfer pool.

A heavy load handling accident would not result in water leakage severe enough to uncover the spent fuel. The maximum load carried over the spent fuel pool is that of a fuel assembly; however, it is not possible to drop a fuel assembly on the spent fuel pool liner plate. In addition, integrity of the spent fuel pool will not be breached due to a fuel cask drop in the fuel transfer pool since each of the pool structures are separate and distinct.

Pool water level indication is provided by individual high and low water level alarms. The alarms are actuated by deviation from normal water level (Elevation 128 feet-8 inches) of plus or minus

6 inches. The alarms are annunciated in the Fuel Handling Building at the spent fuel pool and in the Control Room.

Annunciation of an alarm will be confirmed by visually checking the spent fuel pool water level. Alarms may be expected to occur occasionally due to gradual changes in pool water temperature and surface evaporation. If needed, makeup will be added. Alarms occurring with unusual frequency or for reasons not readily apparent will be further investigated. Frequent inspections will be made of the Fuel Handling Building sump to identify any abnormalities. In addition, a high sump level alarm is provided in the Control Room.

The normal source of makeup water to the spent fuel pool is the Demineralized Water System which distributes water from two 500,000-gallon demineralized water tanks. The tanks and the distribution system do not have seismic classification. Makeup is also available from the primary water storage tank via the primary water makeup pumps (Seismic Class II) and from the CVCS holdup tanks via the holdup tank recirculation pump (Seismic Class II).

Valves have been installed on the existing 6-inch spare nozzles on both RWSTs (364,500 gallons each). These tanks are Class I (seismic). For beyond design basis scenarios, a portable pump, with appropriate suction and discharge connections and hose, has been provided with the capability to deliver approximately 100 gpm makeup water flow from one of the RWSTs directly to the spent fuel pool. The valves installed on the RWSTs will be locked, closed and capped, and will be under administrative control. The portable pump and hose will also be under administrative control to ensure constant and timely availability.

Up to 100 gallons per minute of makeup is also available from the RWST via the refueling water purification loop.

If a leaking fuel assembly is stored in the spent fuel pool, a small quantity of fission products may enter the cooling water. Fission products and other contaminants are removed by the spent fuel pool purification loop.

A failure analyses of system pumps, heat exchangers and valves is presented in Table 9.1-3.

The spent fuel pool water is normally limited to 149°F except in circumstances as previously described. Boron concentration in the pool fluid is maintained at a minimum of 2,000 ppm.

9.1.3.4 Tests and Inspections

The active components of the system are in continuous use during normal plant operation and no additional periodic tests are required. Periodic visual inspections and preventive maintenance are conducted following normal industrial practice.

9.1.4 Fuel Handling System

The Fuel Handling System consists of equipment and structures utilized for handling new and spent fuel assemblies in a safe manner during refueling and fuel transfer operations. The Fuel Handling System is shown on Figure 9.1-5.

The design of the Fuel Handling System conforms to the recommendations of Regulatory Guide 1.13.

The Fuel Handling System components are not generally designed to Class I (seismic) requirements because they do not fit within the definition of Class I (seismic) structures. Those components are designed to Class III requirements. The spent fuel racks, spent

5. Hoist drive circuit in either direction is operated only when either the OPEN and CLOSED indicating switch or the gripper is actuated.

6. Bridge and trolley drives are interlocked in the direction of the Transfer System so that the bridge is prevented from traveling beyond the core area unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is moved beyond the edge of the core.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing due to the Design Basis Earthquake (DBE). The manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper under the DBE.

Fuel Handling Crane

The fuel handling crane is a semi-gantry type crane used to transport new or spent fuel assemblies between their shipping container, storage racks and upending device. Fuel assemblies are handled by means of a special tool suspended from the crane hook. When handling spent fuel, the hook travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

The fuel handling crane is a separate structure from the spent fuel pool bridge, although they can be coupled together to enable the two to travel as a single unit. The fuel handling crane and its components are designed as Class I (seismic). The crane components are designed to remain intact during a design basis seismic event.

Fuel Transfer System

The Fuel Transfer System, shown on Figure 9.1-5, is an electrically driven underwater conveyor car that runs on tracks extending from the refueling canal through the transfer tube and into the transfer pool. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised to a vertical position in the transfer pool.

During plant operation the conveyor car is stored in the refueling canal. A blind flange is bolted on the transfer tube to seal the reactor containment. A valve seals the transfer tube on the Fuel Building side.

New Fuel Elevator

New fuel is lowered into the transfer pool in the New Fuel Elevator. The carriage (basket) of the New Fuel Elevator is also specially designed to support and position fuel assemblies during fuel repairs, as well as to handle new fuel assemblies during new fuel transfer. When the New Fuel Elevator is used for fuel repairs, elevator hard stops are installed on the rails above the elevator basket to prevent inadvertently raising an irradiated fuel assembly above a safe shielding water depth.

Cask Handling Crane

The cask handling crane is a bridge and trolley crane used to: 1) transfer new fuel containers from the truck bay to the laydown area near the new fuel storage area, and 2) move spent fuel shipping casks from the transfer pool to the decontamination pit and to the truck bay.

The arrangement of the fuel handling area limits the drop height from the cask handling crane to 30 feet, except over the truck bay area and fuel transfer pool. Administrative control will limit the lift of the cask handling crane to 30 feet or less above the area of the truck bay.

The main hoist is driven by an electric motor connected to the hoist gearing which drives drum pinion that in turn meshes with the gear attached to end of the cable drum. Each end of the hoist cable is attached to end of the cable drum with wire rope anchor. There is sufficient grooving on the drum to accommodate all of the cable that is required to make the specified lifts. The cable passes from the drum to the center sheaves of the block and then around sheaves mounted on the trolley frame, returning to the

transfer canal and spent fuel pool. The cask is moved within certain areas of the Fuel Handling Building. No equipment required for safe shutdown is located in any of these areas.

The physical arrangement of the Fuel Handling Building is such that the transfer pool is separated from the spent fuel pool. The cask can travel only over the transfer pool. For this reason, no analysis of cask drop in the transfer pool was required, nor was any performed.

9.1.4.4 Tests and Inspections

Prior to initial fueling, preoperational checkouts of the fuel handling equipment were performed to ensure proper performance of the fuel handling equipment and to familiarize plant operating personnel with operation of the equipment.

Prior to subsequent refueling operations, the equipment is inspected for operability and certain components, such as the fuel transfer car and manipulator crane, are operated to ensure reliable performance prior to moving irradiated fuel.

9.1.5 Control of Heavy Loads

A list of overhead handling systems from which heavy loads can be dropped, resulting in damage to safety-related equipment, is given in Table 9.1-4. Compliance of these systems with the requirements of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," are evaluated in detail in References 1 and 2. These evaluations considered the following factors:

1. Load paths and the location of safety-related components.

2. Measures to ensure heavy load are moved within safe pathways.

3. Written procedures for heavy load handling.

4. Procedures for inspection, testing, maintenance and (crane) operator training.

5. Verification of crane design against the guidelines of industry standards such as CMAA-70 (3) and ANSI B30.2-76 (4).

As a result of the initial study (1), lifting devices are being more clearly marked to indicate lift capacity and to distinguish monorail lifting and nonlifting devices. As a result of the follow-up study (2) Public Service Electric & Gas considers the entire program on the evaluation of heavy loads to be complete.

9.1.6 References for Section 9.1

1. Quadrex Corporation, "Six-Month Response for Control of Heavy Loads 2, Salem Nuclear Station," December 17, 1981.

2. Quadrex Corporation, "Nine-Month Response for Control of Heavy Loads, Salem Nuclear Station Units 1 and 2," February 11, 1985.

3. Crane Manufacturer's Association of America, "Specification for Electric Overhead Traveling Cranes," CMAA-70, 1970.

4. American National Standards Institute, "American National Standard for Overhead and Gantry Cranes," ANSI B30.2.0, 1976.

5. Bradfute, J.L., et. al., "Criticality Analysis of the Salem Units 1 and 2 Fresh Fuel Racks," NFU-VTD-WW-94-08 00, January 1994.

9.2 WATER SYSTEMS

9.2.1 Service Water System

9.2.1.1 Design Basis

The Service Water System (SWS) is designed to supply an adequate supply of cooling water to the reactor safeguard and auxiliary equipment under all credible seismic, flood, drought, and storm conditions. Coolant flow is divided into two portions, namely, the nuclear area and the turbine generator area. These are illustrated on Figures 9.2-1A and B and 9.2-2A and B, respectively. The following equipment is supplied with the SWS.

Reactor Containment Building

Reactor containment fan cooler units.

Auxiliary Building

1. Component cooling heat exchangers
2. Diesel generator units
3. Chiller condensers
4. Auxiliary equipment lube oil coolers
5. Auxiliary equipment room coolers

Turbine Generator Building

1. Steam generator feed pump coolers
2. Station air compressor units

3. Turbine lube oil coolers

4. Turbine auxiliary cooling water heat exchangers

Pump Intake Structure

1. Traveling screenwash and strainer backwash

2. Service water pump bearing lubrication

3. Service water pump motor bearing coolers

4. Sodium hypochlorite dilution water

9.2.1.2 System Description and Operation

Each unit is equipped with six vertical turbine-type pumps which provide strained Delaware River Water to the plant before discharging via the circulating water outlet piping. The pumps for both units are installed in an enclosed intake structure which features four independent pump room compartments containing three pump units each. Each group of three pumps is valved into one of two independent, full-sized, supply headers per unit, which are situated in alternating compartments of the intake structure. Two 15,000 gallon pressurized storage tanks (10,000 gallon normal water volume) are connected to the SW piping downstream of the SW pumps. These normally-isolated tanks are designed to be rapidly placed in service through fast opening isolation valves in order to keep the CFCU SW piping solid following a Loss Of Off-site Power (LOOP) or a LOCA/MSLB concurrent with a LOOP event. A double-valved, normally open, interconnection between the two pump headers is provided to permit the continued operation of the system with any combination of pumps in the event of a supply line

outage. Each supply line to the nuclear services portion of the SWS normally feeds approximately 1/2 of the total nuclear area requirement for one unit. In addition, each line is valved at all terminations and provided with double-valved interconnections to permit the removal of either supply line from service without affecting plant operations. Recirculation control (to enable smooth multiple combination pump operation) is provided for each pump room compartment. Pump discharge is recirculated back to the pump intakes through a valve serving the three pumps within each compartment. These valves are modulated by service water pressure measured within the common manifold connecting the discharge of the three pumps within each compartment. Pump requirements on a per unit basis for various plant conditions are outlined as follows:

Plant Conditions	No. of Pumps
1. Normal Operation	4
2. Loss-of-Coolant Accident (LOCA)	
a. Safety Injection Phase	2
b. Recirculation Phase	3 (1)

(1) Minimum recirculation requirements can be met with two pumps.

Emergency diesel generators are provided to power three pumps during a failure of normal power supply. The total system requirements during various modes of plant operation are listed on Table 9.2-1 which lists the required pumping requirements based on a maximum river temperature of 90°F.

The reactor containment fan cooler (RCFC) units are supplied by individual lines from the containment area service water header. Each inlet and discharge line penetrating the containment wall is

provided with a remotely-operated, automatically controlled shutoff valve. This provision allows each fan cooler to be isolated on an individual basis from outside the containment area. Protection from thermally induced overpressure events in the RCFC coils is provided by the installation of bypass lines. These bypass lines are installed in each RCFC loop and discharge back into the SW system downstream piping. These bypass lines preclude overpressure conditions from developing in portions of the system during automatic valve sequencing.

The supply side control valves for each RCFC modulate to control pressure at the inlet to the RCFC discharge flow control valves during normal operation. If this pressure control valve for a RCFC did not open, or continues to modulate following an SEC signal, the SW flow to the RCFC would then be significantly reduced. The resulting high pressure drop across the valve, coupled with a low Service Water flow, would cause flashing and steaming to occur in the RCFC. The steam and water mixture in the discharge header would then meet and possibly cause accelerated water damage to occur. To prevent this occurrence during accident conditions these valves are interlocked such that they must be full open to enable the RCFC to start in low speed (accident mode). The valves will only modulate to control pressure when the RCFC is running in high speed (normal mode).

buses. Adminstration control may be required to maintain pump performance at a higher level in order to ensure acceptable system margins. The pumps for each unit are mounted in two individual dewaterable cells of the intake structure with three pumps to a cell. The intake structure, shown on Figure 9.2-3, is physically apart from the turbine condenser circulating water pump intake. The pumps are arranged to afford adequate submergence during the lowest credible water level elevation of 76.0 feet. The motors are protected from flooding by the pump room compartments which are watertight to Elevation 126'-0" with wave run-up protection to Elevation 128'-0", and which contain sump pumps. Automatic traveling water screens are provided at each intake cell and combine with full-depth trash racks to filter debris from the incoming flow. A mobile mechanical trash rake unit is provided to maintain unobstructed passageways at the trash racks. Two-foot-wide fish-escape passages are located abreast of the traveling screens to minimize the entrapment of fish in the individual intake cells. The primary method to prevent organic buildup in the heat exchangers and piping is by injecting sodium hypochlorite into each of the six service water headers. Additionally or alternately, sodium hypochlorite may be injected at the suction of each service water pump. Each pump discharges to an automatic, self-cleaning strainer and check valve prior to entering the compartment supply header.

The SWS intake structure is located about 200 yards from the Delaware River shipping channels. It is expected that shipping will not approach the intake since the channel is marked by buoys and lights. Due to the large distance between the intake and the shipping channel, vessels which may be adrift can be secured, anchored, or grounded before coming into the vicinity of the intake. In the event that small unattended barges do drift into the vicinity of the intake, marine dock bumpers have been installed to prevent damage to the structure.

The six service water pumps for each unit are arranged in groups of three pumps each, and each group of pumps for one unit is installed in alternate watertight compartments inside the intake structure, as

indicated on Figures 9.2-1A and B. Each service water pump is recessed approximately 50 feet from the river face of the intake. Based on the above, damage or blockage to two adjacent compartments of the intake can occur without cutting off the supply of service water to each unit.

In the event that a river borne oil spill occurs which could affect the service water intake, floating oil spill booms will be installed as needed to protect the two end cell fish-escape passages opening to the river to prevent oil from entering the intake at any river water level above 81 feet. A curtain wall at Elevation 81 feet extending across the entire intake structure, except in the fish escape passages, prevents any oil from entering the intake at any river level above this elevation. Lowest recorded river water level is 83 feet-1 inch. The vertical turbine type service water pumps take suction at Elevation 71'-6" for Johnston Pump Co. pumps, which is below the minimum credible river water level of 76 feet. Based on the above, oil floating on the river surface will not be drawn into the pumps. Should the river water level drop below elevation 81 feet with water borne oil present, the plant would be shut down.

The SWS is designed for Class I (seismic) conditions except for the turbine area service water piping outside of the service water intake structure, which is of non-Class I (seismic) design. The Class I (seismic) service water piping inside the service water intake structure which supplies the turbine area is provided with two motor-operated valves, SW-20 and SW-26, in series, to isolate the non-Class I (seismic) portion of the system upon receipt of a safety injection signal or a blackout. The two motor-operated valves in series are powered from separate vital buses to ensure isolation of the non-Class I (seismic) portion of the SWS.

The hypochlorite system piping inside the service water intake structure is designed for Class II (seismic) conditions, but the pipe supports are designed to Class I (seismic) criteria.

The separated redundant service water lines between the service water pumps and the Unit 1 component cooling heat exchangers are not located in open trenches as such, but rather are constructed of reinforced concrete pipe completely buried in the ground. Thus, in effect, they are located in "separate trenches." The principal supply line piping runs are separated by about 13 feet. This separation, in conjunction with the depth at which they have been buried, makes these lines essentially invulnerable to damage from a single postulated event.

The above discussion also applies to the service water piping to the Unit 2 component cooling heat exchangers except for one section of piping running along the west side of the Auxiliary Building. Though not buried, this piping is located within a 4 foot-6 inch thick reinforced concrete pipe tunnel. The redundant supply lines within the tunnel are separated by a 3-foot thick reinforced concrete wall, again precluding coincident failure due to a single event.

Status is displayed and control of each service water pump is available on the main control panel so that an operator can determine if an abnormal number of pumps is operating. In addition, indication of the 14 and 24 pump in "TEST" is displayed on the auxiliary annunciator during performance of surveillance testing. Status and control of all SWS isolation valves and motor-operated header block and tie valves is also available to the operator in the Control Room. The motor-operated valve operators (with the exception of the Turbine Area isolation valves) complete their closing or opening cycle in 1 minute while the containment isolation valves can close in 10 seconds. The Turbine Area isolation motor operated valves have a more rapid operating time of a maximum of 37 seconds.

The rupture of a large pipe or other event causing a high system flow demand will be indicated to the operator by decreasing pump header pressure shown on the main control panel. Low pump header pressure will be alarmed to the main control room. If pump discharge header pressure continues to fall, and outside power is available, a backup service water pump will start automatically.

In the event that a pipe rupture occurs in a watertight pump compartment in the service water intake structure, which is beyond the capacity of the 125-gpm sump pump, high sump level for the affected compartment will be alarmed to the Control Room. The Control Room operator can remotely close the tie valves and header block valves at the intake structure to isolate the affected compartment and remotely start the remaining pumps in the other pump compartment to permit an orderly plant shutdown.

In the event that a main yard supply header is ruptured, the affected header can be isolated by the Control Room operator who can also open the tie valves at the Auxiliary Building. Rupture of a header pipe for Unit 2 in the pipe tunnel can also be detected by high level to the Control Room alarm from the sumps each containing 200 gpm pumps. The Control Room operator can determine the affected header by remotely closing the intake tie valves and observing which pump header is affected by low-low pressure. Once the rupture yard header is isolated, the intake tie valves can be opened and all service water pumps made available.

Service water piping in the Auxiliary Building is, for the most part, accessible during operation for inspection by the operators.

Generic Letter (GL) 96-06 was issued by the NRC to notify utilities of safety significant issues that could affect containment integrity and equipment operability during accident conditions. The SW system is designed to withstand the effects of events described in GL 96-06. These GL concerns of thermally induced overpressure, the development of two-phase flow regions, and column separation or voiding leading to the possibility of waterhammer events are addressed by system modifications.

A pressurized tank in each of the two service water headers is installed to serve the containment fan cooler unit (CFCU) loops. The supply lines between the tanks and the SW headers have fast opening valves to allow flow in the event of a LOOP (Loss Of Off-site Power) or LOOP/LOCA. The tanks have a volume of 15,000 gallons each and are pressurized with nitrogen, and discharge into the SW system upon a loss of off-site power. The vessels are sized to contain sufficient water inventory to keep the SW piping full for all postulated operating and single failure conditions. A separate building houses the storage tanks, piping and the storage tank instrumentation and controls.

Each storage tank has non-safety related redundant level, temperature and pressure instruments. Local instrumentation will include level, temperature, and pressure indications. The main control room is provided with a common "tank trouble" overhead annunciator and an individual alarm for each storage tank. The non-safety related classification is considered acceptable on the basis that critical system parameters are periodically monitored during normal operation to assure operational readiness of the system. During normal operations and following a LOOP, the supply tanks are filled by a makeup water pump located at each storage tank. The pumps are manually controlled and are supplied from the SW system.

The storage tank discharge valves are air operated butterfly valves designed to spring open rapidly upon a blackout. The valves are powered from redundant safety related 125 VDC channels and and are designed to be energized to open and fail closed on a loss of control power. This design assumes one of the two flow paths for each tank will be operable while ensuring against spurious operation. Air is required to close the valves. Redundant undervoltage relays installed on the 4KV vital buses are combined in a 3 out of 3 logic to energize the valve solenoid, venting air from the operators to open the valves.

Bypass lines are installed to protect from thermally induced overpressure events in the CFCU piping. These bypass lines are installed in each CFCU loop and discharge back into the SW system's downstream piping.

In the event that a pipe rupture occurs in the service water piping inside the containment, the difference between flows entering and leaving the containment will be sensed and alarmed to the Control Room. High level alarms in the containment sump and the fan cooler drain pot will also be transmitted to the Control Room. The Control Room operator can remotely close the containment isolation valves to isolate the leaking fan cooler unit.

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In the event that radiation is detected at one of the service water outlets from the containment, the condition is alarmed in the Control Room. The final decision to isolate the coils is based on plant conditions, analyses, and indications.

The service water flow through the containment fan cooler units is indicated on the control console along with a differential flow measurement which alarms under flow mismatch conditions. A flow mismatch could occur due to a leak in the fan cooler unit in the containment area.

A temperature detector monitors the fan cooler outlet temperature, which is indicated on the control console; high water temperature could be an indication of inadequate flow.

The service water flow through the No. 11 and 12 component cooling heat exchangers is limited to a nominal operating value of 10,000 gpm by means of the inlet flow control valve. The valve is controlled by an indicating controller mounted in an instrument panel which is located in the Auxiliary Building in the vicinity of the heat exchanger. The outlet valve provides the normal means of service water flow control based on component cooling outlet temperature. In addition, a flow transmitter alarms a service water high flow condition on the overhead annunciator in the Control Room.

The service water flow through the Salem Unit 2 No. 21 and 22 Component Cooling Heat Exchangers is controlled by means of a cascade control system which simultaneously throttles both the inlet and outlet control valves with a common control air signal. The valves are throttled to maintain component cooling water outlet temperature as the primary parameter, and flow will be limited to a nominal operating value of 10,000 GPM as the secondary parameter. The indicating valve control system is mounted on an instrument panel which is located in the Auxiliary Building in the vicinity of the heat exchanger. In addition, a flow transmitter alarms a service water high flow condition on the overhead annunciator in the Control Room.

In certain post-accident alignments, available system pressure will be limited such that the Component Cooling Heat Exchanger original design flow of 10,000 gpm may not be attainable for both heat exchangers. As noted in Table 9.2-1, the currently evaluated design (minimum required) flow has been defined to be 8,000 gpm with 90° F water. The capability of meeting or exceeding this flow, where required, is demonstrated in detailed system calculations.

Material inspection, fabrication, and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

Radiographs of Nuclear Class 3 cement-lined pipe were difficult to interpret. The 1970 addenda to B31.7 allowed 100-percent magnetic particle inspection in lieu of random radiography. This provision was also incorporated into Section III, 1971 Edition. The SWS contains Nuclear Class 3 cement-lined pipe for which this alternate inspection method was utilized. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

For the original cement lined piping the use of a later code was restricted to inspection and did not involve any requirements from Section III such as material, stress calculations, etc., that would modify our original design. Consequently, other requirements from a later code would not be applicable. Therefore it is believed that the integrity of field welds has not been compromised and that we have complied with our commitment to use ANSI B31.7 whenever possible. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

As part of a reliability improvement program, replacement of portions of the system piping was initiated in 1988 for both Unit 1 and Unit 2. The replacement material selected after an extensive qualification program is a 6% molybdenum Austenitic Stainless Steel, which is furnished to the material requirements of the ASME code Section III, Division 1. However, fabrication, inspection and installation of this piping material is in accordance with ANSI B31.7 and therefore compliance with the commitment to utilize ANSI B31.7 wherever possible has again been maintained. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

In order to provide enhanced accuracy and repeatability for periodic ASME Section XI performance testing, a full flow Service Water Pump surveillance test line was added to the Service Water Intake

Structure by DCP 1EC-3047 in 1991. This line is connected to the Unit 1 Service Water pipe at the 30" crossover line between the SW17 valves in a section of pipe located in bay #2 (Ref. Fig. 9.2-1A Sh. 2) and into the Unit 2 Service Water pipe at the 30" crossover line between the SW17 valves in a section of pipe located in bay #3 (Ref. Fig. 9.2-1B Sh. 1). These connections are 16" in size and are connected to two 16" butterfly valves which are normally closed. The 16" lines reduce down to 12" lines and penetrate outside the east wall of the Intake Structure through watertight seals. Outside the wall the two lines connect together and run around to the north wall. The line expands to 20" for the flow measuring section which has a long straight run that is essential for the flow measurement element located along the north wall. The line then runs through a butterfly valve used for initial filling prior to each flow test and exhausts to the Trash Basket back to the river. The two 16" butterfly valves provide double isolation and form the boundary between the safety related and non-safety related portions of the line. All the supports on this line are designed to Seismic Class I criteria.

The surveillance line provides the capability to accomplish a performance test for each individual Service Water Pump utilizing a direct recirculation flow path around the Intake Structure through a high accuracy flow element that is independent of the rest of the plant.

9.2.1.3 Design Evaluation

The SWS is designed to remain operable under each of the following conditions:

1. Any one pump failure and one pump under maintenance

2. Any one pump failure and two pumps under maintenance provided that:
   1. No more than one pump per intake bay is removed from service, and
   2. No more than one pump per vital bus is removed from service

3. One main supply header failure

4. Loss-of-coolant accident coincident with loss of offsite power and subsequent 4-kV vital bus failure.

5. Failure of components such as individual valves that receive active control signals to change position or modulate are addressed as single active failures.

   Updates to the design evaluation were made in 1997 to address GL 96-06 concerns relative to maintaining the containment cooling portions of the system free of voids or column separations, above saturation pressure and protected from thermally induced overpressure. In order to support these updates, positions were established based on the design and licensing basis of the Service Water System regarding certain types of single failures. The key positions are identified below:

   a. The failure, or spurious actuation of a remotely operated, manually controlled, or power operated (i.e., either air or motor) valve that does not have any automatic actuation signal is not considered to be a credible failure.

   b. Failures of check valves to move to their intended position following an accident scenario are considered passive failures.

The minimum engineered safeguards equipment required to safely shut down the unit will not be limited by any of these failures.

As part of the GL 96-06 modifications, RCFCs are maintained free of voids or column separation, above saturation pressure, and protected from thermally induced overpressure events during all normal operating and abnormal events.

9.2.1.4 Tests and Inspections

The system was hydrostatically tested prior to station operation. All active components (valves, pumps, and controls) were functionally tested prior to startup. Surveillance requirements for inservice inspection and testing of components is in accordance with the Technical Specifications.

9.2.2 Component Cooling System

An independent Component Cooling System, shown on Figure 9.2-4, is provided for each unit. All information in this section refers to one unit. Unit 2 is of a similar design.

9.2.2.1 Design Bases

The system is designed to remove residual and sensible heat from the Reactor Coolant System (RCS) via the Residual Heat Removal (RHR) System during plant shutdown, cool the spent fuel pool water and the letdown flow to the Chemical Volume and Control System (CVCS) during power operation and provide cooling to dissipate waste heat from various primary plant components. The design of the Component Cooling System is based on a maximum service water supply temperature of 90°F.

Active system components which are considered vital to the cooling function are redundant. Redundancy of components in the Component Cooling System, when provided, does not degrade the performance or reliability of any system which the Component Cooling System serves. Any single active or passive failure in the system will not prevent the system from performing its design function.

The system design provides means for detection of radioactivity entering the system from the RCS and its associated auxiliary systems and includes provisions for isolation of system components.

9.2.2.2 Codes and Classifications

All piping and components of the Component Cooling System will be designed to the applicable codes and standards listed in Table 9.2-2. Component cooling water contains a corrosion inhibitor to protect the carbon steel.

9.2.2.3 System Description

The Component Cooling System consists of three component cooling pumps, two component cooling heat exchangers, a component cooling surge tank, cooling lines to various components being cooled, and associated piping, valves, and instrumentation. The component coolant flows from the pumps, through the shell side of the component cooling heat exchangers, shell and tube type, or through the component cooling water side of the component cooling heat exchangers, plate type, through the components being cooled, and back to the pumps. The surge tank is connected to the suction side of the component cooling pumps. Makeup water is supplied to the loop near the surge tank.

During normal full power operation, one or two component cooling pumps and one component cooling heat exchanger accommodate the heat removal loads. The standby pump and the standby heat exchanger provide backup during normal operation. Operation of all component cooling pumps and both component cooling heat exchangers is required for removing residual and sensible heat during a normal plant shutdown. Failure of one of these components increases the time required for shutdown but does not affect the safe operation of the plant.

In the event of a LOCA one pump and one heat exchanger are capable of fulfilling system requirements. Three main cooling headers are provided: two isolable headers which supply cooling water to essential safety equipment, and one header which supplies cooling water to the other plant auxiliaries. With this arrangement, long-term cooling of the Engineered Safety Features under accident

9.3 PROCESS AUXILIARIES

9.3.1 Compressed Air System

The Compressed Air System provides the station with a reliable supply of clean, oil free air which is directed to various locations for services as required. The system is illustrated on Figures 9.3-1A and B.

9.3.1.1 Design Bases

The system provides a reliable supply of clean, oil free, dry air at temperatures and pressures suitable for use as control air and for containment penetration cooling, as well as for miscellaneous services and maintenance.

The Compressed Air System is designed such that any single failure will not result in loss of function.

9.3.1.2 System Description

9.3.1.2.1 General

The Compressed Air System is supplied by three motor-driven, oil free, centrifugal compressors which draw air from the atmosphere. The intakes of the air compressors are located to avoid drawing in toxic or corrosive gases. Each compressor has a capacity of 4000 scfm at 110 psig discharge pressure. One compressor is typically running to satisfy the normal requirements of station air and control air for both units as well as to supply containment penetration cooling air for both units. A second compressor serves as standby. A third compressor is available when required. Each compressor is furnished with a 1000-hp motor, intake filter-silencer, blow-off silencer and total closure controls, constant pressure controls only, intercoolers, aftercooler, and moisture separator. The compressors discharge into two independent service air headers, with an air receiver tied to each header.

The station air header for each unit is supplied from either of the two service air headers. This station air header provides operating and service requirements at various locations.

The containment penetration cooling system for each unit is furnished with two supply lines. The normal supply is taken from the station air header and the backup supply from either of the two service air headers.

9.3.1.2.2 Control Air

The Control Air System for each unit consists of a dual header arrangement as shown on Figures 9.3-2A and B. This control air for each unit is supplied through two distinct parallel paths. One path is supplied from the Unit 1 Station Air System and the other is supplied from the Unit 2 Station Air System. Control air for the safety-related portions is automatically backed up by an emergency control air compressor. Control air is fed from the Station Air System through heatless, desiccant-type air dryers.

The dual station service air headers are fed by three 100-percent capacity air compressors, any one of which can supply the total service and control air requirements for both units.

In addition to the normal air supply from the service air headers, each system has an emergency control air compressor complete with its own dryer and accessories to supply the safety-related headers. The emergency control air for either system may be directed to supply air for the opposite system through a valved connection. Each emergency control air compressor motor is energized from the standby ac power supply. The Emergency Control Air System is designated Class I (seismic) and is located in a Class I (seismic) structure.

Each emergency control air compressor has a capacity of 500 scfm at 110 psig and is driven by a 125-hp motor. Accessory equipment includes an independent heatless desiccant-type air dryer, intake filter, silencer, intercooler, aftercooler, moisture separator, inlet control valve, relief valve and automatic condensate trap and drain. The emergency control air compressors with teflon piston rings and stainless steel cylinder liners. Cooling of the emergency control air compressors is provided from the safety-related Chilled Water System. In the event that the Chilled Water System is not available, the Service Water System (SWS) serves as a backup.

Operational or test data that verify the functional reliability of the emergency control air compressors were not initially available although stress analysis calculations by the manufacturer indicated that the compressor could withstand both operational and seismic loadings simultaneously.

9.3.2.3 System Evaluation

The Sampling System is not required to function during an emergency, nor is it required to take action to prevent any emergency condition.

Samples are collected under a hood provided with a vent to the building Exhaust Ventilation System. Liquid leakage in the sample sink is collected in the sink and drained to the WDS. Any leakage from the system inside of the containment (i.e., valve stem leakage) is collected in the containment sump.

The Sampling Room and the sample hood are ventilated to reduce the potential for airborne radioactive exposure of operating personnel.

Sufficient length is provided in the reactor coolant sample line to reduce personnel exposure from short-lived radionuclides. Shielding is provided as necessary to reduce personnel exposures. The operating procedures will specify the precautions to be observed when purging and drawing samples.

The system is designed to be operated on an intermittent basis under administrative control except for steam generator blowdown sampling which is a continuous operation. The system is normally closed with no flow, except for the steam generator blowdown samples. Sample lines penetrating the containment are equipped with remote-operated isolation valves which close on receipt of a containment isolation signal.

In the event of a LOCA, the malfunctions or failures presented in Table 9.3-3 could occur without loss of integrity of the containment.

9.3.2.4 Tests and Inspection

System operation is verified by normal, periodic collection of samples.

9.3.2.5 Instrumentation and Control

Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink.

9.3.3 Equipment and Floor Drainage System

9.3.3.1 Design Bases

Equipment and floor drains are provided to drain radioactively contaminated water into sumps for transfer to the Liquid Waste Disposal System (See Section 11.2). In many cases equipment drainage is provided by permanently installed lines which eliminate (or reduce) surface and airborne contamination. Permanently piped equipment vents are also provided to enable various mechanical components to be vented to the respective building Ventilation System to preclude the direct release of potentially radioactive gases to the building atmosphere.

9.3.3.2 System Description

The contaminated floor drains and equipment vents and drains flow diagrams are shown on Figures 9.3-4A and B and 9.3-5A and B.

All liquid drains originating in the Containment and Auxiliary Buildings are considered potentially radioactive and are therefore drained to the Liquid Waste Disposal System. The drain connections on nearly all components within these areas are permanently piped to the equipment drain system. Exceptions include some room cooler condensate drain piping, the Component Cooling System and certain portions of the

CVCS containing 12 percent boric acid. Hose connections are provided where it is impractical to have a permanently piped drain in which case equipment drains can be temporarily connected by hose to a local floor drain. These provisions eliminate or reduce the possibility of inadvertently allowing radioactive drains to contaminate concrete floor areas and the building atmosphere.

Condensate drain piping from room cooler drip pans is extended to the floor for free discharge to the nearest existing floor drains.

In the Auxiliary Building the floor drains at Elevations 84 feet, 100 feet and 122 feet are piped to the waste holdup tanks. Elevation 64 foot drains are piped to the waste holdup tanks via the Auxiliary Building sump tanks and sump tank pumps. All drains below the elevation of the Auxiliary Building sump tank drain to the waste holdup tank via the Auxiliary Building sump and the Auxiliary Building sump pump.

A floor drain, 4 inches in diameter, in the immediate vicinity of each charcoal filter bank, directs the drainage or deluge water to the waste holdup tanks, either directly or via sump pumps.

In the Containment Building, all equipment drains to the WDS from the containment sump.

In the Fuel Handling Building, the equipment drains are piped to the WDS via a fuel handling area sump.

With the exception of Nuclear Steam Supply System (NSSS) tanks that are blanketed with nitrogen, all tanks containing potentially contaminated waste are permanently vented to the suction side of the Auxiliary Building exhaust fans. This ensures that the tanks are maintained at a slight negative pressure to eliminate the possibility of introducing airborne contamination to the Auxiliary Building atmosphere.

9.3.3.3 System Design

The contaminated floor and equipment drain piping was originally designed to ASME/ANSI B31.1, while material selection, fabrication, inspection, testing, installation and quality controls were in accordance with ASME/ANSI B31.7. The original design classification of the system was based on early interpretation of the Regulatory Guides during the construction period, and the system was classified to be non-safety related, Nuclear Class III and non-seismic. Based on the current revisions of the Regulatory Guides and ANSI standards, the system has been reclassified to be non-safety related, non-Nuclear (Quality Group D) and non-seismic. Supplemental quality assurance requirements (Augmented D) have been incorporated to the applicable piping specification section to maintain the quality level recommended by Regulatory Guide 1.143.

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9.3.4 Chemical and Volume Control System

The CVCS is used to 1) adjust the concentration of boric acid, i.e., the chemical neutron absorber for reactivity control, 2) maintain the proper water inventory in the RCS, 3) provide the required seal water flow for the reactor coolant pump shaft seals, 4) process reactor coolant letdown for reuse of boric acid and reactor makeup water, 5) maintain the proper concentration of corrosion-inhibiting chemicals in the reactor coolant, 6) maintain the reactor coolant activities to within design limits, and 7) provide borated water for safety injection. The system is also used to fill and hydrostatically test the RCS.

During normal operation, this system also has provisions for supplying the following chemicals:

1. Regenerant chemicals to the evaporator condensate and deborating demineralizers

2. Hydrogen to the volume control tank

3. Nitrogen as required for purging the volume control tank

4. Hydrazine hydrogen peroxide and lithium hydroxide as required via the chemical mixing tank to the charging pumps suction

9.3.4.1 Design Bases

9.3.4.1.1 Redundancy of Reactivity Control Systems

Two independent Reactivity Control Systems, preferably of different principles, shall be provided.

In addition to the reactivity control achieved by the rod cluster control assemblies (RCCA) as detailed in Sections 7 and 4, reactivity control is provided by the CVCS which regulates the concentration of boric acid solution neutron absorber in the RCS.

predominantly filled with hydrogen and water vapor. The hydrogen within the tank is, in turn, the supply source to the reactor coolant. Fission gases are removed from the system by venting the volume control tank to the WDS prior to a cold or refueling shutdown.

During plant shutdown, dissolved hydrogen in the RCS must be removed prior to opening the RCS for maintenance or refueling. Hydrogen removal can be performed in either or a combination of the following methods: 1) The VCT level can be raised and lowered repeatedly to "burb" the hydrogen-rich VCT gas space to the WDS. When the level is lowered, fresh nitrogen is admitted to the gas space. 2) Hydrogen peroxide is added to the RCS to react with the dissolved hydrogen to form water.

To enter the RCS the coolant flows from the volume control tank to the charging pumps which raise the pressure above that in the RCS. The coolant then enters the containment, passes through the tube side of the regenerative heat exchangers, and returns to the RCS. A portion of the high pressure charging flow is filtered and injected into the reactor coolant pumps between the pump impeller and the shaft seal so that the seals are not exposed to particulate matter in the reactor coolant. Part of the flow cools the lower radial bearing and enters the RCS through a labyrinth seal on the pump's shaft. The remainder, which is the shaft seal leakage flow, is filtered, cooled in the seal water heat exchanger and returned to the suction of the charging pumps. An alternate path provides means for returning seal water to the volume control tank.

Coolant injected through the reactor coolant pump labyrinth seals joins with the reactor coolant. An equal amount of reactor coolant returns to the volume control tank by the normal letdown flow path through the regenerative heat exchanger. When the normal letdown route is not in service, this reactor coolant letdown returns to the suction of the charging pumps through the excess letdown and seal water heat exchangers.

The cation bed demineralizer, located downstream of the mixed bed demineralizers, is used intermittently to control cesium activity in the coolant and also to remove excess lithium which is formed from the B^{10} (n, α) Li^{7} reaction.

Boric acid is dissolved in water in the batching tank to a concentration between 3.75 to 4.0 weight percent. The batching tank is jacketed to permit heating of the batching tank solution

with low pressure steam. One of two boric acid transfer pumps is used to transfer the batch to the boric acid tanks. Small quantities of boric acid solution are metered from the discharge of an operating boric acid transfer pump for blending with the water supplied to makeup for normal leakage, or for increasing the reactor coolant boron concentration during normal operation. Electric immersion heaters maintain the temperature of the solution in the boric acid tanks high enough to prevent precipitation.

During plant startup, normal operation, load reductions and shutdowns, liquid effluents containing boric acid flow from the RCS through the letdown line and are collected in the holdup tanks or the volume control tank. As liquid enters the holdup tanks, the nitrogen cover gas is displaced to the gas decay tanks in the WDS through the waste vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle. A recirculation pump is provided to recirculate and transfer liquid from one holdup tank to another.

Liquid effluent in the holdup tanks is processed through a recycle processing train. This liquid is pumped by the gas stripper feed pumps through the evaporator feed ion exchangers which primarily remove lithium and long-lived cesium. The liquid then flows through the ion exchanger filter, and into the gas stripper section of the combined boric acid evaporator gas stripper package where dissolved gases are removed from the liquid. These gases are vented to the Gaseous Waste Disposal System.

The liquid effluent from the gas stripper section enters the boric acid evaporator.

The vapor produced in the boric acid evaporator leaves the evaporator condenser and is pumped through a condensate cooler where the distillate is cooled to the operating temperature of the evaporator distillate demineralizers. After non-volatile

evaporator carryover is removed by one of the two evaporator distillate demineralizers, the distillate then flows through the distillate filter and accumulates in one of the two monitor tanks. The evaporator bottoms left behind in the boric acid evaporator are concentrated to approximately 12 weight percent boric acid.

Subsequent handling of the condensate is dependent on the results of sample analysis of the monitor tank contents. Discharge from the monitor tanks may be pumped by either of the two monitor tank drain pumps to the primary water storage tank, recycled through the evaporator distillate demineralizers, returned to the holdup tanks for reprocessing in the evaporator train or, if the sample analysis of the monitor tank contents indicates sufficiently low levels, the contents may be discharged to the environment via the WDS (Section 11).

Boric acid evaporator bottoms are discharged through a concentrates filter to the concentrates holding tank to the Boric Acid Storage Tanks or the hold-up tanks, depending on sample analysis and plant requirements.

The concentrated solution can also be pumped from the evaporator to the WDS portable demineralizer or waste evaporator for additional reprocessing before being placed in containers. These containers can then be stored at the station site for ultimate shipment offsite for disposal.

The deborating demineralizers can be used intermittently to remove boron from the reactor coolant near the end of core life when boron concentration is low. When the deborating demineralizers are in operation, the letdown stream passes through the mixed bed demineralizers and then through the deborating demineralizers and into the volume control tank after passing through the reactor coolant filter.

During shutdown, hydrogen peroxide is added to the RSC via the Chemical Mixing Tank to dissolve radionuclides and non-radioactive metals from piping and equipment to allow their removal by the CVCS demineralizers.

During plant cooldown when the residual heat removal loop is operating and the letdown orifices are not in service, a flow path is provided to remove fission products, corrosion products and other impurities. A portion of the flow leaving the residual heat exchangers passes through the letdown heat exchanger, mixed bed demineralizers, reactor coolant filter and volume control tank. The fluid is then pumped via the charging pump through the tube side of the regenerative heat exchanger into the RCS.

9.3.4.2.2 Expected Operating Conditions

Tables 9.3-5 and 9.3-6 list the system performance requirements and data for individual system components respectively.

9.3.4.2.3 Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including the expected coolant cleanup flow rate and the demineralizer effectiveness, are presented with the results of the calculations in Appendix I. In these calculations the defective fuel rods are assumed to be present at core loading uniformly distributed throughout the core. The fission product escape rate coefficients are therefore based upon an average fuel temperature.

Tritium is produced in the reactor from ternary fission in the fuel, irradiation of boron in the burnable poison rods (during initial fuel cycle only), irradiation of boron in the control rods, and irradiation of boron, lithium and deuterium in the coolant.

9.3.4.2.4 Reactor Makeup Control Modes

The reactor makeup control is designed to operate from the Control Room by manually preselecting makeup composition to the charging pump suction header or the volume control tank in order to maintain the desired operating fluid inventory in the volume

control tank and to adjust the reactor coolant boron concentration for reactivity control. The operator can stop the makeup operation at any time in any operating mode by remotely closing the makeup stop valves or depressing the makeup mode selector stop pushbutton.

Makeup water to the RCS is provided by the CVCS from the following sources:

1. The primary water storage tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced.

2. The boric acid tanks, which supply concentrated boric acid solution when the reactor coolant boron concentration is to be increased.

3. The refueling water storage tank which supplies borated water for emergency makeup.

4. The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine hydrogen peroxide or pH control chemical (Li^7OH) are necessary.

Makeup for normal plant leakage is regulated by the reactor makeup control which is set by the operator to blend water from the primary water storage tank with concentrated boric acid to match the reactor coolant boron concentration. Makeup is added automatically if the volume control tank level falls below a preset point.

Automatic Makeup

The "automatic makeup" mode of operation of the reactor primary water makeup control provides boric acid solution present to match the boron concentration in the RCS. The "automatic makeup" compensates for minor leakage of reactor coolant without causing

significant changes in the coolant boron concentration.

The operator sets the following equipment in the automatic position:

1. Either primary water makeup pump

2. Either boric acid transfer pump

3. Boric acid flow control valve

4. Primary water flow control valve

5. Charging suction makeup valve

6. Makeup mode selector

By depressing the start pushbutton of the makeup mode selector, the following actions occur when a low level signal is received from the volume control tank:

1. The boric acid transfer pump is switched to high speed and the primary water makeup pump is switched on.

2. The boric acid flow control valve is switched to its respective flow controller.

3. The primary water flow control valve is unblocked.

4. The charging suction makeup valve is open.

The flow controllers then blend the makeup stream according to the present concentration. Makeup addition to either the charging pump suction header or the spray line to the volume control tank causes the water level in the volume control tank to rise. After the level in the volume control tank is restored, the primary water flow control valve closes, the boric acid transfer pump is

a minimum factor of 10 during power operation. The anion resin rapidly converts to a borate form and thereafter does not remove boron from the reactor coolant.

Each demineralizer is sized to accommodate the maximum letdown flow. One demineralizer serves as a standby unit for lithium management and corrosion product control or for use if the in-service demineralizer becomes exhausted.

The demineralizer vessels are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity for approximately one core cycle with one percent defective fuel rods.

Cation Bed Demineralizer

A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of Li^7 which builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 μc/cc with 1 percent defective fuel. The demineralizer is used intermittently to control cesium.

The demineralizer vessel is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with resin retention screens. The cation bed demineralizer has sufficient capacity for approximately one core cycle with 1 percent defective fuel rods.

Resin Fill Tank

The resin fill tank is mobile and is used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a valve and a flexible hose spool piece that may be connected to any one of the demineralizer fill lines. The

demineralizer water and resin slurry can then be sliced into the demineralizer by opening the valve.

Reactor Coolant Filter

The filter collects resin fines and particulates from the letdown stream. The vessel is provided with connections for draining and venting. The nominal flow capacity of the filter is equal to the maximum purification flow rate. Disposable synthetic filter elements in a cage assembly are used.

Volume Control Tank

The volume control tank is an operating surge volume compensating in part for reactor coolant releases from the RCS as a result of level changes. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant at 25 to 50 cc per kg of water (STP).

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibriate the gas and liquid phases. A remotely operated vent valve discharging to the WDS permits removal of gaseous fission products which are stripped from the reactor coolant and collected in the tank.

Charging Pumps

Three charging pumps are provided for injection coolant into the RCS. Two are centrifugal pumps and the third is a positive displacement pump equipped with variable speed drive. All parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other material of adequate corrosion resistance. The centrifugal pump packing glands and positive

displacement pump stuffing box are provided with leakoffs to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage is piped to the drain header for disposal. The pump design prevents lubricating oil from contaminating the charging flow. The integral discharge valves on the positive displacement pump act as check valves.

The positive displacement pump is designed to provide the full charging flow and the reactor coolant pump seal water supply during normal seal leakage and normal letdown. The centrifugal pumps have a higher flow capacity and are used during periods of maximum letdown or purification flow. Each pump is designed to provide rated flow against a pressure equal to the sum of the RCS normal maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve, and equipment pressure losses at the design charging flows. A suction stabilizer and pulsation dampener are provided on the suction and discharge, respectively, of the positive displacement pump to attenuate the inherent pressure pulsations that are caused by the reciprocating actions of the pump.

The positive displacement charging pump is used to hydrotest the RCS.

Under normal conditions, either the positive displacement charging pump or a centrifugal charging pump will take suction from the volume control tank and discharge to the normal charging and reactor coolant pump seal water injection paths. If the positive displacement pump is not used, one of the centrifugal charging pumps is operated. The flow paths remain the same, but flow control is accomplished by a modulating valve on the discharge side of the centrifugal pumps. For periods when maximum letdown or purification flow is required, a centrifugal pump is operated to provide the necessary flow. The centrifugal charging pumps also serve as safety injection pumps in the Emergency Core Cooling System (Section 6).

Chemical Mixing Tank

The primary use of the chemical mixing tank is for the injection of various chemicals for RCS water chemistry control. These include the injection of caustic solutions for ph control, hydrazine for oxygen scavenging and hydrogen peroxide for chemical degassing and corrosion product solubilization.

The capacity of the chemical mixing tank is determined by the quantity of 35 percent hydrazine solution necessary to increase the hydrazine concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare solution of pH control chemical for the RCS.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools an amount of reactor coolant letdown equal to the nominal injection rate through the reactor coolant pump labyrinth seal, if letdown through the normal letdown path is not usable. The unit is designed to reduce the letdown stream temperature from the cold leg temperature to 195°F. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with the reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

Seal Water Heat Exchanger

The seal water heat exchanger removes heat from several sources: the reactor coolant pump seal water returning to the volume control tank, the reactor coolant discharge from the excess letdown heat exchanger and the centrifugal charging pump bypass flow. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet to prevent leakage in either direction and undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

9.4 HEATING, VENTILATION, AND AIR CONDITIONING SYSTEMS

9.4.1 Control Area Air Conditioning System

The Control Area Air Conditioning System (CAACS) and the Control Room Emergency Air Conditioning System (CREACS) are designed to maintain room temperatures within limits required for operation, maintenance and testing of plant controls, and permits continuous occupancy under normal and design accident conditions.

9.4.1.1 Design Bases

The CAACS maintains the control room area ambient temperatures of 76°F dry bulb and a maximum of 50 percent relative humidity based on outside air temperatures ranging from 0°F winter dry bulb to 95°F summer dry bulb and 78°F summer wet bulb during normal and emergency conditions.

The CREACS maintains room ambient temperatures inside the Control Room Envelope (CRE) within 55° to 85°F during emergency conditions based on outside air temperatures ranging from 0°F winter dry bulb to 95°F summer dry bulb and 78°F summer wet bulb during emergency conditions.

In addition, the CAACS/CREACS design bases provides for the following:

(1) Protection of the CRE and control room areas (relay and control equipment rooms) from infiltration of fire, smoke, or airborne radioactivity by use of minimum leakage penetrations, weather stripped doors, absence of outside windows, and by maintenance of a positive pressure during normal operation.

(2) Protection of the CRE from a radiological design bases accident by filtering airborne activity and maintaining the CRE at 1/8 inwc positive pressure differential between the outside environment and adjacent rooms.

(3) Protection from airborne toxic gas or hazardous chemical releases outside the control room area.

(4) Protection from the smoke generated inside or outside the control room area.

(5) Maintains ambient temperatures within 55° to 85°F in the control room and adjoining equipment room for personnel comfort and instrument accuracy and from 65° to 85°F in the Relay and 125 VDC Battery Rooms during normal plant operating conditions.

(6) Remains operable during a design basis seismic event.

9.4.1.2 System Description

The control room area for each unit consists of the unit control room, a data logging room, a control equipment room, and a relay room. The operator ready room, conference room or Operations Support Center (OSC), control room supervisor's office areas, and both units control rooms are located in a common protected area or Control Room Envelope (CRE). The CRE area is serviced by both units CAACS during normal operating conditions and both units CREACS during emergency conditions.

Normal access to the control area is attained through the Auxiliary and Service Buildings. The control area is enclosed in a Class I (seismic) structure. The air handling equipment for each control area is housed in the equipment room adjacent to its respective control room inside the Auxiliary Building. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1. The CAACS is shown in Figures 9.4-1A and B. The area adjacent to the control room area (which is comprised of the work control center, field SRO office and a toilet room) is separated from the control room area envelope, does not contain any safety related equipment and is therefore provided with an independent non-safety related system consisting of a roof-top heating and cooling unit, a toilet exhaust fan, and non-seismically supported ductwork, which are also shown on UFSAR Figure 9.4-1A.

The CAACS consist of a filter enclosure equipped with medium and low efficiency filters, three vane-axial fans (one standby), a multi-zone coil unit with three cooling coils and one heating coil, air distribution ducts and electrically or pneumatically operated dampers (with manual backup operators). Each CAACS primarily serves its units equipment room and relay room areas. The operator ready room, control room supervisor areas, OSC, and both units data logging and control rooms are serviced by both units CAACS during normal operation and smoke generated inside or outside the CRE.

The CREACS, a portion of the CAACS, operates to ensure continuous occupancy of operating personnel in the CRE under emergency conditions. The CREACS supplies cooled high-efficiency particulate air (HEPA) and charcoal filtered air to the CRE when actuated by the Solid State Protection System (SSPS) or control room intake high radiation signal. The CREACS consists of a filter enclosure equipped with HEPA and charcoal filters, a cooling coil, two vane-axial fans (one standby), supply and return ducts to the control room envelope, outside air intakes (crosstied between unit 1 and 2 CREACS filter units), distribution plenum above the control room conference room, and electrically or pneumatically and manually operated dampers (with manual backup operators).

9.4.2 Auxiliary Building Ventilation System

9.4.2.1 Design Bases

The Auxiliary Building Ventilation System is designed for long-term continuous operation during normal and emergency modes of plant operation to provide consistent levels of temperature, cleanliness, and negative pressure within the building. Standby

equipment is included in the system to assure the maintenance of design conditions within the building and thus preclude the uncontrolled release of radioactivity to the environs.

Auxiliary Building Ventilation equipment is utilized in performing containment purging. Containment purging is an intermittent operation performed in accordance with the requirements of 10CFR20. The equipment in the Auxiliary Building Ventilation System is available to purge the containment during normal reactor shutdown. Containment purging is limited by administrative controls as described in Section 9.4.4.3.1.

The total capacity of fans and filters is designed for the maximum required ventilation rate. That is, total capacity is based on summertime ventilation of the Auxiliary Building during normal power operation. This system operates to limit the average temperature of the Auxiliary Building to 110°F or less, and to maintain the Auxiliary Building boundary at a slight negative pressure.

The Auxiliary Building Ventilation System is designed to maintain a year-round range of average temperatures within the Auxiliary Building of 60-110°F. This is the temperature range chosen to size the ventilation equipment and not necessarily the space temperature requirements. Auxilliary Building equipment has been evaluated to operate at area temperatures to 110°F. Hot water coils in the supply air units are designed to provide 60°F air to the Auxiliary Building in winter and no less than 45°F air to the Containment Building. The design basis outdoor temperature is 0°F (winter) and 95°F (summer). Both values satisfy more than 99 percent of the conditions experienced at the site area annually.

A 24,000 cfm capacity charcoal filter is included in the Exhaust Air System, usually in standby, to remove gaseous iodine from the exhaust effluent during emergency operation. This filter is designed to adsorb at least 90 percent of the elemental and methyl iodines contacted at rated flow. No credit is taken for the removal of organic iodine in Section 15.4.1.3. The charcoal filter is capable of treating the effluent from areas served having the highest potential for radioactive contamination during a LOCA.

Individual room coolers, in conjunction with the once-through ventilation air, are designed to limit the ambient temperature at the vital pumping equipment to the following values:

Positive Displacement Charging Pump	110°F
Containment Spray Pumps	115°F
Residual Heat Removal	120°F
Auxiliary Feedwater	120°F
Centrifugal Charging Pump	120°F

Note: 1) In the event that the 12 (22) Component Cooling Water (CCW) Room Cooler fails concurrent with the operation of both CCW Pumps in the room, temperatures in the 12 (22) CCW Heat Exchanger and Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 132°F.

2) In the event that the Safety Injection Pump Room cooler fails concurrent with operation of both SI pumps, temperature in the SI Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 146°F.

These temperatures help to assure long-term and reliable operation of the pumps, motors, controls and instrumentation and accessibility to this equipment for maintenance as required.

The exhaust fan-filter units in the Auxiliary Building Ventilation System and their controls are designed to seismic Class I criteria. They can be powered from the standby ac power supply during a loss of

offsite power. The distribution ductwork for the system is designed to seismic Class II criteria. Room coolers are seismic Class I and powered from the Standby AC Power System. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1.

The design arrangement of the HEPA and charcoal filter exhaust units provides various filtering modes for ventilating the Auxiliary Building continuously and purging the containment intermittently. In order to purge the containment, standby equipment must be available.

All the filtering modes are designed to satisfy the requirements of normal power operation, normal reactor shutdown, refueling, LOCA, post-loss-of-coolant accident cleanup and minor contamination problems. The modes of operation are as follows:

NORMAL VENTILATION (Normal operations)

HEPA UNIT 11 (21) FROM ECCS ONLY and HEPA UNIT 12 (22) FROM AUX. NORMAL
OR
HEPA UNIT 11 (21) FROM ECCS ONLY and HEPA UNIT 13 (23) FROM AUX. NORMAL
OR
HEPA UNIT 12 (22) FROM ECCS ONLY and HEPA UNIT 13 (23) FROM AUX. NORMAL
AND
EITHER SUPPLY FAN

EMERGENCY VENTILATION (Emergency plant operations)

HEPA UNIT 11 (21) FROM ECCS + CARBON UNIT 14 (24) and HEPA UNIT 12 (22) FROM AUX. NORMAL
OR
HEPA UNIT 11 (21) FROM ECCS + CARBON UNIT 14 (24) and HEPA UNIT 13 (23) FROM AUX. NORMAL
OR
HEPA UNIT 12 (22) FROM ECCS + CARBON UNIT 14 (24) And HEPA UNIT 13 (23) FROM AUX. NORMAL
AND
EITHER SUPPLY FAN

The starting, stopping, and mode of operation of the system is manually controlled from the Control Room. The exception to this is the pump room coolers which will auto-start on rising temperatures in their respective pump rooms while in auto position. After being placed in operation, the system automatically maintains building temperature and pressure within satisfactory limits. System performance and building conditions are monitored from the Control Room.

9.4.2.2.2 System Operation

Automatic controls are provided to maintain the building within the design values of pressure and temperature. A temperature switch provides two position modulation of fan capacity from 2/3 airflow capacity to full capacity as the average building temperature varies from 60°F in winter to 110°F in summer. Simultaneously, a differential pressure controller modulates the exhaust fan capacity between 2/3 and full to maintain the building at a slight negative pressure with respect to outside. This temperature and pressure control for the Auxiliary Building continues to operate even when containment purging is required.

In the event of a LOCA, the Auxiliary Building ventilation equipment continues to operate in its normal mode. That is:

1. One of the two supply air units provides two position modulation of filtered air to the building in response to building exhaust air temperatures.

2. Two of the three HEPA filter units and exhaust fans operate while fan inlet guide vanes continuously modulate flow in response to building negative pressure.

The Control Room operator will align the charcoal filter to the exhaust flowpath from the potentially radioactive safeguard areas during the recirculation phase as required. This is accomplished by actuating controls in the Control Room. Activation of the charcoal filter is confirmed by Control Room indication which indicates that the necessary air diversion dampers are in the

correct position. If proper operation is not indicated within a few seconds, the dampers can be manually positioned locally.

The following operations occur automatically:

1. Room coolers will start automatically and operate continuously at full capacity in response to the above normal ambient temperatures that develop as the RHR, containment spray, charging, safety injection, component cooling, and auxiliary feedwater pumps are started. However, in the event that vital power is being provided by diesel generators, the room coolers for the RHR charging, and containment spray pumps may be delayed for up to 20 minutes.

2. Containment purging is terminated.

Thereafter, operator action is required if trouble or failure alarms sound in the Control Room:

1. The standby supply air unit can be energized if the operating unit signals low air flow, high or low supply air temperature, or a break in the hot water heating coil.

2. The standby HEPA filter exhaust unit can be placed in service if either of the other two operating units experience high differential pressure. In this event, the charcoal filter can be repositioned simultaneously with another HEPA filter (either 11 (21) or 12 (22)) unit if necessary.

3. The standby exhaust fan can be energized if either of the two operating fans experience an operational problem.

4. The loss of power fail-safe damper positions ensure one HEPA filter exhaust unit and charcoal filter unit are available for the ECCS equipment areas. The remainder of the Auxiliary Building areas are exhausted through the HEPA filter unit to the Unit vent without passing through the charcoal filter unit.

Auxiliary Building and the containment. This reduces the potential hazard of irradiated particles being transported throughout the building and reduces the loading on the exhaust filters. The HEPA type exhaust filters, in turn, continuously minimize the release of particulate radioactivity to the environment while the standby charcoal filter is available to adsorb gaseous contamination. The design capability of a three-part high level filtration train ensures that all exhausted emissions from the Auxiliary Building and the containment are within the requirements of 10CFR20.

Availability of the Auxiliary Building supply and exhaust ventilation equipment is ensured by connection to the standby ac power supply.

The room coolers located near vital pumping equipment are single capacity units. The total capacity of the room cooler(s) in a given area, in conjunction with the exhaust air flow rate, is designed to limit the area temperature to the design values even if all pumping equipment in the area is operated continuously. In the event that the Safety Injection Pump Room cooler fails concurrent with operation of both SI pumps, temperature in the SI Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 146°F. Similarly, in the event that the 12 (22) Component Cooling Water (CCW) Room Cooler fails concurrent with operation of both CCW pumps in the room, temperatures in the 12 (22) CCW Heat Exchanger and Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 132°F.

9.4.2.4 Test and Inspections

All components of the Auxiliary Building Ventilation System are subjected to a test and inspection program. This program is similar to that described for the Containment Ventilation System (Section 9.4.4), except the resistance to LOCA pressure and temperature transients is not applicable to the Auxiliary Building equipment.

9.4.3 Fuel Handling Area Ventilation

9.4.3.1 Design Bases

The Ventilation System is designed to exhaust the spent fuel pool area at 60 air changes an hour within a 10-foot height above the pool during design conditions for spent fuel storage. Out of a system operating capacity of 20,000 cfm, 15,000 cfm is exhausted from the spent fuel pool area (10,000 of which is extracted right at the pool surface) and the remaining 5,000 cfm of system capacity ventilates other parts of the building.

Because of the potential for radioactive releases from the spent fuel, defective fuel cladding or a fuel handling mishap, the building is maintained at a slight negative pressure to assure inleakage of air rather than outleakage.

The total capacity of the Ventilation System is designed to maintain the building between 60°F and 105°F. Although there is no direct control of the humidity in the building and there can be instances of 100-percent relative humidity around the spent fuel pool when the outdoor air is damp, the relative humidity under design conditions is expected to be less than 70 percent.

The exhaust filter units, fans and controls are designed to Class I (seismic) criteria. The discharge ductwork from the fuel handling area to the plant vent is also designed to Class I (seismic) criteria. The supply air equipment is served by the Normal AC Power System only, whereas the exhaust air equipment can be energized from the Standby AC Power System in the event of a loss of offsite power. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1.

9.4.3.2 System Description

9.4.3.2.1 General Description

The fuel handling area is a structure separate from other unit structures and is provided with its own ventilation system. This system is a once-through filtered air system that continuously ventilates the normal operating areas (fuel pools, decontamination pit, electrical equipment room and sump tunnel). The Fuel Handling Area Ventilation System is shown on Figures 9.4-3A and B.

The Ventilation System consists of the following equipment:

1. One 100-percent capacity supply air unit with particulate filters at about 80-percent cleaning efficiency and a heating coil for winter-time tempering of the supply air

2. Two 50-percent capacity exhaust fans

3. One 100-percent capacity HEPA filter exhaust unit and one 100-percent capacity HEPA and charcoal filter exhaust unit available for standby

4. Controls and instrumentation

5. Distribution ductwork

6. Pressure relief damper

All exhaust effluent is diverted to the standby HEPA and charcoal exhaust unit in the event that radioactivity levels within the building become excessive. Control of the system and surveillance of building conditions are accomplished from the Control Room.

Air is distributed with overhead ducts for supply and exhaust, as well as embedded exhaust ducts around the spent fuel pool.

Supply air enters the building at the cask storage area, flows through the building to the spent fuel pool area, and is exhausted to the unit vent where the total plant effluent is continually monitored for radioactivity. Supply air may also enter through the pressure relief intake dampers at the truck bay when the supply fan is shutdown and only one exhaust fan is running. The Ventilation System maintains the building under a slight negative pressure and exhausts the heat and humidity emitted from the spent fuel pool.

9.4.3.2.2 System Operation

Normally the supply air unit, both exhaust fans and the HEPA exhaust filter unit operate continuously. The supply air unit operates at a constant volume. Exhaust air is varied through inlet guide vanes on each exhaust fan which are controlled by a differential pressure controller to maintain a negative pressure greater than or equal to 0.125 inch water gage in the building. When the building temperature reduces to 60°F, the heating coil and controls at the supply air unit are energized to maintain the building at approximately 60°F.

In the event that a local radiation monitor detects excessive radioactivity in the building and alarms in the Control Room, the operator can divert the building effluent from the HEPA exhaust unit to the standby HEPA and charcoal exhaust unit. Also during the event, an automatic initiation of the exhaust fans will take place for Unit 2.

Additional alarms in the Control Room will signal adverse operating conditions: low or high supply air temperature, low air flow from the supply or exhaust fans, clogged HEPA filters, and insufficient negative pressure in the building.

9.4.3.3 Design Evaluation

The heating and ventilating of the fuel handling area is based on outdoor design conditions of 0°F in winter, 93°F dry bulb and 79°F wet bulb in summer. These values satisfy 99 percent of the

weather conditions experienced annually at the Salem site and offer a high degree of assurance that satisfactory temperature conditions will be maintained.

Directing the air flow from areas of least contamination to areas of higher contamination is accomplished in two ways. First, the building is maintained at a negative pressure such that outdoor air leaks into the building rather than building air leaking out. Secondly, air flow within the building is from the cask storage area to the spent fuel pool area.

Efficient filtration of the supply air minimizes the inventory of airborne particulates within the building. This reduces the rate of dirt buildup on the HEPA filter exhaust units and extends their useful life. Whereas the supply air filters can be replaced easily and safely as required, the HEPA exhaust filters are potentially radioactive and less maintenance is desirable.

The heat, humidity and potential radioactivity in the building is confined to the spent fuel pool area. Seventy-five percent of the building exhaust occurs in that area, and the 60 air changes per hour over the pool is a rapid exhaust rate. Two-thirds of this exhaust rate takes place just inches above the pool water through numerous, high velocity (2000 fpm) exhaust ports spaced around the pool periphery. These ports act to vacuum the surface of the pool and effect early capture of pool emissions.

The exhaust portion of the Fuel Handling Area Ventilation System includes one filtration unit containing only roughing and HEPA filters, and one filtration unit containing roughing and HEPA filters, and carbon absorbers. There are two (2) 50% capacity exhaust fans and one (1) 100% capacity supply fan.

The charcoal filter train is normally at standby and is inspected and tested periodically for availability, especially prior to refueling. This administrative control will assure the preparedness of the filter train and clogging of the train during the relatively short period of refueling or during a fuel handling accident is not anticipated.

Overheating of the carbon filters from radioiodine loading is not expected to occur. An analysis was performed using Safety Guide No. 25 assumptions assuming all the airborne radioiodine released during a design basis fuel handling accident was adsorbed on the charcoal filters. The resulting heat generation rate is negligible (less than 100 Btu/hr) compared to the heat generation rate required to elevate the carbon temperature (with airflow through the filters) to the point that de-adsorption or ignition occurs (greater than 100,000 Btu/hr).

The exhaust ductwork and exhaust fan-filter units leading from the fuel handling structure to the plant vent are seismic Class I design. Exposed ductwork along the walls within the structure is seismic Class II. The supply air unit, located below the fuel handling operating floor, is of non-seismic standard construction. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described is Section 3.8.4.4.1.

In the event of a seismic disturbance or a fuel handling accident that causes the failure of non-Class I equipment, the primary function of the Ventilation System will still be maintained. That is, the seismic Class I portion of the exhaust system will continue to operate, creating a negative pressure within the structure, and pass the exhaust through HEPA and charcoal filters. There would be no increase in building differential pressure and, therefore, radioactivity would be contained within the building.

Unit 1

A gravity pressure relief damper is provided in the exterior wall of the shipping bay. This damper is pinned closed.

Unit 2

A gravity pressure relief damper and a manual volume damper are provided in the exterior wall of the shipping bay.

9.4.3.4 Tests and Inspections

All components of the Fuel Handling Area Ventilation System are subjected to a program of tests and inspections. This program is similar to that described for the Containment Ventilation System (Section 9.4.4.4) except that resistance to LOCA pressure and temperature transients is not applicable to the fuel handling area.

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 Fire Protection

9.5.1.1 Fire Protection Program

The Salem Generating Station Fire Protection Program has been established to prevent significant fires, to ensure the capability to shutdown the reactors and maintain them in a safe shutdown condition, and to minimize radioactive releases to the environment in the event of a significant fire. The fire Protection Program implements the philosophy of defense-in-depth protection against the hazards of fire and its associated affects on equipment important to safety by:

1. Preventing fires from starting.

2. Rapidly detecting, controlling, and promptly extinguishing those fires that do occur.

3. Providing protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.

The Salem Generating Station Fire Protection Program consists of design features, equipment, personnel, and procedures that provide defense-in-depth protection of the public health and safety. The Salem Fire Protection Program is described in several documents:

- A program description which establishes the basis for the fire protection program at the Salem Generating Station. The Report identifies and documents principal fire protection commitments made between the Nuclear Regulatory Commission and Public Service Electric & Gas Co. through a narrative description of the Fire Protection Program. The report also provides a comparison to Appendix A of BTP APCSB 9.5-1.

- A report which establishes the basis for demonstrating a capability to achieve and maintain post-fire safe shutdown in accordance with Appendix R to 10 CFR 50. This report also establishes the information and format of the information to be utilized for long-term compliance to Appendix R to 10 CFR 50.

- A report which identifies the cables and the routing of the cables that were utilized in the assessment of post-fire safe shutdown.

- A report which outlines the Fire Hazards Analysis performed for Salem Generating Station in accordance with USNRC Branch Technical Position BTP-APCSB 9.5-1 Appendix A "Guidelines for Fire Protection for Nuclear Power Plants".

- A report which defines and assesses the adequacy of the fire area boundaries in the Salem Generating Station as recommended by Generic Letter 86-10.

The information contained in these reports is summarized in the following sections.

9.5.1.1.1 Organization for Fire Protection

The President and Chief Nuclear Officer is the upper level management position who has management responsibility for the formulation, implementation, and assessment of the effectiveness of the Fire Protection Program for the Nuclear Business Unit.

The Vice President - Technical Support is the management position who is responsible for formulating and implementing a program or programs to control and maintain the design aspects of the Fire Protection program.

The Vice President - Plant Support is the management position who is responsible for formulating and implementing a program or programs to control and maintain fire prevention aspects of the Fire Protection Program and the readiness to detect and suppress fires and safely shut down the plant. The Vice President - Plant Support is also responsible for establishing a method of tracking and correcting Fire Protection Program deficiencies; establishing program requirements for implementing the aspects of the Fire Protection Program relative to fire prevention and housekeeping, readiness to detect and suppress fires, and a trained fire brigade; and ensuring any required maintenance of fire protection systems is completed promptly and effectively.

The fire brigade responds to the respective (plant) Operations Superintendent during plant emergencies.

The Vice President - Operations reporting directly to the CNO/PNBU is responsible for maintaining procedures for safely shutting down the plant in the event of a fire and providing trained operators in support of safe shutdown and fire brigade activities.

The Director - Quality, Nuclear Training and Emergency Preparedness reporting to the Chief Nuclear Officer and President - Nuclear Business Unit is responsible for ensuring that personnel designated to operate the plant are trained such that they can safely shut down the plant and maintain it in a safe shutdown condition in the event of a fire.

The Director - Quality, Nuclear Training and Emergency Preparedness is the management position responsible for defining a QA program for fire protection and for conducting independent verification and review for compliance with Fire Protection Program requirements.

9.5.1.1.2 Use of Combustible Materials

The use of combustible materials at the Salem Generating Station is controlled by station procedures. Administrative controls are established to minimize the quantity of combustibles that a safety related area may be exposed to.

Procedures outline the methods to be used to ensure safe handling and limitations on the use of combustibles.

The use of ordinary combustibles such as paper, wood and plastic is minimized in the station. When wood is used for scaffolding, it is of the flame retardant type.

The bulk storage of hydrogen is in a separate area, outside plant structures. Additional hydrogen storage is in the Turbine Building and on the Auxiliary Building Roof. Signs are posted in the storage areas prohibiting smoking, open flames, and spark producing equipment.

Bulk Class A materials, such as charcoal filter medium, are not stored in safety related areas of the station.

h. Containment (Areas 1 and 2 FA-RC-78)

This exemption is from the requirements of Section III.G.2 of Appendix R to 10 CFR Part 50 to the extent that it requires that redundant cables and equipment within containment be separated by at least 20 feet of horizontal distance free of intervening combustibles or be separated by a radiant energy shield.

i. Pipe Tunnel - Elevation 84 feet (Area 12 FA-PT-84)

This exemption is from the technical requirements of Section III.G.2 of Appendix R to 10 CFR Part 50 to the extent that it requires that redundant shutdown systems be separated by at least 20 feet free of intervening combustibles and be protected by automatic fire detection and suppression systems. Specifically, redundant systems are separated by less than 20 feet and the tunnel is not protected by an automatic fire suppression system.

j. CO_2 Equipment Room - Elevation 84 feet (Areas 1 and 2 FA-DG-84F)

This exemption is from the technical requirements of Section III.G.2 of Appendix R to 10 CFR 50 to the extent that it requires separation of redundant shutdown systems by 1 hour fire barriers and protection by automatic fire detection and suppression systems. Specifically, redundant shutdown cables are not protected by an automatic fire suppression system.

9.5.1.5 Support Equipment

9.5.1.5.1 Emergency Lighting

The lighting system at Salem Generating Station consists of normal lighting, emergency lighting, self-contained emergency battery lighting, and portable hand held lights. A description of the complete system is contained in Section 9.5.3.1 of the Salem UFSAR.

The emergency lighting provided for Appendix R safe shutdown is a self-contained lighting system consisting of fixed and portable hand held lights. Each lighting unit consists of a battery, charger, lights and electronics and it is rated to supply 8 hours of lighting.

The fixed lighting units are energized automatically upon a loss of power and they are located in access routes to and within areas where shutdown functions must be performed.

The portable hand held lighting units are located in the Appendix R locker and they are used as a supplement to the fixed lighting units and for exterior access and egress to operate safe shutdown equipment outside the power block.

9.5.1.5.2 Portable Radios

A portable radio communication system as described in Section 9.5.2 of the Salem UFSAR is provided for use of the fire brigade as well as operations personnel involved in emergency activities. This system does not interfere with the communication equipment of the security force. For post fire safe shutdown, the operators will use portable hand held radios. The radio system including repeaters and power supplies has been designed to be available for a fire in any of the alternate shutdown areas.

9.5.1.5.3 Ventilation and Smoke Removal

Ventilation systems for the station were not specifically designed to provide automatic smoke and heat venting. Natural convection type ventilation is not used at this station. The station ventilation systems provide forced-convection flows for specific areas. Smoke and corrosive gases from a fire may be discharged directly to the outdoors by nature of the once-through ventilation design applied throughout the station (with the exception of the Reactor Containment).

Ventilation systems serving the safety related areas are controlled from the Control Room. Charcoal filters are provided in the exhaust ducts to absorb smoke and corrosive gases for public protection, except for the systems serving the service water intake, diesel-generator and fuel oil storage rooms, battery rooms, switchgear rooms and penetration areas. A special part of the

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10.2 TURBINE GENERATOR

10.2.1 Design Bases

The Steam and Power Conversion System is designed to convert the heat produced in the reactor to electrical energy. Heat absorbed by the Reactor Coolant System (RCS) is transferred to the feedwater in four steam generators. The Feedwater System provides sufficient feedwater flow to the four steam generators where removal of heat from the RCS results in sufficient steam formation to drive the turbine generator units as follows:

	Unit 1	Unit 2
At 100% Reactor Power		
Gross Output, MWe	1158	1182
Anticipated Net Output, MWe	1115	1139
Maximum Calculated Load		
Gross Output, MWe	1176	1231
Anticipated Net Output, MWe	1130	1185

10.2.2 System Description

10.2.2.1 Turbine Generator

The turbine is a four-casing, tandem-compound, six flow exhaust, 1800 rpm unit. The Unit 1 last stage blades are 44 inches long. The Unit 2 last stage blades are 47 inches long. The turbine shaft is directly connected to the ac generator. A brushless exciter (Unit 1) or alternator-exciter (Unit 2) is coupled to the generator. The generator is hydrogen cooled with water-cooled stator windings. It is rated at 1,300,000 KVA at 75 psig hydrogen pressure, 0.90 PF, 0.48 SCR, 3 phase, 60 cps, 25 KV, and 1800 rpm. Generator rating, temperature rise, and insulation class are in accordance with the latest ANSI standards.

The voltage regulator has redundant digital controllers (primary and secondary) and a back-up manual analog regulator. The voltage regulator automatically transfers to back-up manual analog regulation upon a digital controller problem or protective circuit initiation. After automatic or manual transfer to the back-up manual analog regulator, the voltage regulator may be transferred to its secondary digital controller.

The turbine consists of one double-flow high pressure (HP) element in tandem with three double-flow low pressure (LP) elements. Moisture separation and two stage reheating of the steam is provided between the HP and LP elements utilizing six horizontal-axis, cylindrical-shell, combined moisture separator-reheater assemblies. Three of these assemblies are located on each side of the LP turbine elements.

Additional moisture removal is accomplished inside the turbine by use of blades constructed with slingers. The slingers direct the moisture radially to the turbine casing drain passages.

A diagram of the Lubricating Oil System is shown on Figure 10.2-1. The turbine generator bearings are lubricated by a conventional oil system. The main lubricating oil pump, a centrifugal volute type, is mounted on the end of the turbine shaft and supplies all of the lubricating oil requirements for the Lubrication System during normal operation. The ac motor-driven auxiliary centrifugal lubricating oil pump supplies bearing oil when operating the unit on turning gear during startup and shutdown. The dc motor-driven emergency lubricating oil pump operates in the event of loss of ac power or failure of the ac motor-driven pump, to protect the turbine generator bearings during coastdown. The hydraulic lift pump supplies a small quantity of high pressure oil to selected turbine bearings during startup. The seal oil backup pump provides oil to the Hydrogen Seal System upon loss of the seal oil pump in the Hydrogen Seal System. Part of the oil in the reservoir is continuously bypassed to an oil purification system. Lubricating oil is received in the makeup tank and is pumped by the positive displacement pump to either the lubricating oil storage tanks, reservoir or lubricating oil purifier.

10.2.2.2 Steam Cycle

Steam from each of the four steam generators supplies the tandem-compound turbine generator unit. The steam enters the HP

An automatic turbine load runback can also be initiated by a trip of either main feedwater pump when turbine power is greater than 70%.

The extraction nonreturn valves are closed through an air pilot valve which is actuated by the loss of autostop oil pressure when the turbine generator is tripped.

An electrical speed limiting device is incorporated in the Electro-Hydraulic Control System. This mechanism dumps the operating fluid from the turbine governor and intercept valves allowing spring pressure to close the valves. When turbine speed decreases, and the overspeed condition clears, the signal is removed and the valves reopen. This is not considered a turbine trip, but rather a speed limiting device to prevent an overspeed condition which would result in a turbine trip.

To prevent potential damage to the turbine due to the generator motoring, an electrical reverse power device interlocked with the turbine trip signal is incorporated. This protective measure ensures that the turbine is tripped before the generator circuit breakers are open, and provides the 30 seconds delay between the turbine trip and the generator trip upon detection of motoring condition.

10.2.2.5 Instrumentation

Instrumentation is provided to continuously monitor and/or alarm such turbine generator parameters as the following:

1. Generator load
2. Shaft vibration at bearings
3. Shaft eccentricity
4. Shell expansion
5. Differential expansion between turbine shell and rotor
6. Turbine speed
7. Turbine casing temperatures
8. Bearing temperatures
9. Hydrogen gas and stator cooling water temperatures
10. Generator frequency
11. Exhaust hood temperature
12. Condenser vacuum
13. Stator winding temperatures
14. Hydrogen pressure and purity
15. Bearing lube oil and hydraulic oil pressure

10.2.2.6 TURBINE OVERSPEED PROTECTION

a. At least one turbine overspeed protection system shall be operable in Modes 1, 2 and 3.

   With one stop valve or one control valve per high pressure turbine steam lead inoperable and/or with one reheat stop valve or one reheat intercept valve per low pressure turbine steam lead inoperable, it is necessary to restore the inoperable valve(s) to operable status within 72 hours or close at least one valve in the affected steam lead; otherwise isolate the turbine from the steam supply within the next six hours.

b. With the above required turbine overspeed protection system otherwise inoperable, within six hours either restore the system to operable status or isolate the turbine from the steam supply.

Surveillance Requirements

a. Each of the following valves in the Turbine Overspeed Protection System must be demonstrated operable by the direct observation of movement through at least one complete cycle from running position:

- Four high-pressure turbine stop valves
- Four high-pressure turbine control valves
- Six low-pressure hot reheat stop valves
- Six low-pressure hot reheat intercept valves

b. The operability testing shall be performed for each of the following conditions:

1. Prior to admitting steam to the turbine during each startup unless performed within the last seven days.
2. Following a startup, within 24 hrs. of attaining manufacturer's recommended power level for performing Turbine Valve Testing.
3. At a frequency not to exceed one year.

Note: The above valves are to be tested at a frequency consistent with the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Testing Frequency", and in accordance with the established NRC acceptance criteria for the probability of a missile ejection incident of 1.0E-5 per year, in no case shall the test interval for the above valves exceed one year.

c. The Turbine Overspeed Protection System shall be demonstrated operable:

1. at least once every 18 months by performance of a channel calibration on the Turbine Overspeed Protection Systems, and
2. at least one of the above valves shall be disassembled each 40 months to perform a visual and surface inspection of the valve seats, disks, and stems to verify no unacceptable flaws or corrosion. If unacceptable flaws or excessive corrosion are found, all other valves of that type shall be inspected.

d. The Turbine Overspeed Protection System test frequency must also be verified such that the testing frequency maintains the probability of a missile ejection incident within NRC guidelines. This verification must be accomplished every two refueling outages or after modifications to the main turbine or turbine overspeed protection valves.

10.2.3 Turbine Missiles

The subject of turbine missile characteristics, probability of occurrence and protection of essential safety equipment is covered in Section 3.5.

Section 3.5 also deals with characteristics of the turbine discs, blades, and rotors as they relate to the subject of turbine missile formation.

10.2.4 Evaluation

Automatic control actions, alarms and trips are initiated by deviations of system variables from preset values. In every instance automatic control functions are programmed such that appropriate corrective action is taken to protect the RCS as well as the Steam and Power Conversion Systems.

10.2.5 Turbine Generator Test and Inspection

10.2.5.1 Turbine Generator Monitoring

Each turbine generator is equipped with supervisory instrumentation that monitor such variables as pressure, temperatures, flows, speed, vibration, eccentricity, rotor position, casing differential and rotating differential expansion. In the event that abnormal readings are being received, investigations will be made to ascertain the cause of the abnormal readings and, if necessary, the unit will be shut down. Investigations made may consist of nondestructive tests, such as visual, magnetic particle, liquid penetrant, ultrasonic and radiographic, where deemed possible.

Periodic inspections will be made as recommended by the turbine generator manufacturer.

10.3 MAIN STEAM SYSTEM

10.3.1 Design Bases

The Main Steam System is designed to convey saturated steam to the turbine from the four steam generators. Steam is also supplied to the steam generator feedpump turbines, auxiliary feedpump turbine, moisture separator-reheaters, gland sealing steam controllers, and No. 15 feedwater heater. Provision is made to dump up to 40 percent of full load steam flow directly into the condenser (turbine bypass) to aid the reactor in accommodating electric generator load rejections without reactor trip.

The main steam piping from the steam generators through the main steam isolation valves (MSIVs) is classified as Seismic Category I. Beyond the MSIVs, the main steam piping is designed to conventional standards.

The main steam piping in the containment has been analyzed to ascertain the effects of guillotine-type pipe rupture, and restraints have been provided to ensure that such a rupture will not compromise containment integrity.

The pressure retaining components or compartments utilize the following codes as minimum design criteria:

1. System pressure vessels - ASME Boiler and Pressure Vessel Code, Section VIII.

2. System fittings and piping - ANSI Standard Code for Pressure Piping ANSI-B31.1.0, Power Piping. For nuclear piping not supplied by the Nuclear Steam Supply System (NSSS) supplier, material, inspections, fabrication, and quality control conform to ANSI Code for Pressure Piping, ANSI-B31.7, Nuclear Power Piping. Where not possible to comply with ANSI B31.7, the requirements of

ASME III-1971, which incorporated ANSI B31.7, were adhered to.

Principal system valves - Main Steam Safety Valves - ASME Boiler and Pressure Vessel Code, Section III, Class A.

Main Steam Relief Valves - ASME Boiler and Pressure Vessel Code, Section III, Class II (Class I for materials, inspections, fabrication, and quality control).

MSIVs - ASME Boiler and Pressure Vessel Code, Section III, Class II (Class I for materials, inspections, fabrication, and quality control).

Feedwater Isolation Valves - ASME Boiler and Pressure Vessel Code, Section III, Class II or ASME Code for Pumps and Valves for Nuclear Power, Class II (Class I for materials, inspections, fabrication, and quality control) as applicable for individual valves based on procurement documents.

10.3.2 System Description

10.3.2.1 Main Steam System

The Main Steam System is shown on Figures 10.3-1A and B.

The Main Steam System for each unit conveys saturated steam from four steam generators to the high pressure (HP) turbine with less than 40 psi pressure drop. The steam conditions at full load of approximately 3,740,000 pounds per hour, and a density based on 750 psig (nominal) 513°F steam, were used for the system design of both units. Reheat is provided, external to the steam generators, between the HP and low pressure (LP) turbines to 485°F at 163 psig.

For Unit 1, the steam pressure is 814 psig, and the temperature is 522°F at the steam generator exit nozzle. This will result in a steam line pressure 24 psi higher in Unit 1 than in Unit 2.

A turbine bypass system bypasses up to 40 percent of full load flow directly from the main steam lines to the condenser.

In addition, the bypass system supplies steam to the main steam coils of the moisture separator - reheaters (MSR), steam generator feed pump turbines (during low load operation) and the gland steam controller. The auxiliary feed pump turbine is fed from the Main Steam System. Cold reheat steam is used in the No. 3 feedwater heater while hot reheat steam is used to supply the steam generator feed pump turbines.

Four lines convey the steam from the steam generators, in the containment, through the wall penetrations to an anchored mixing bottle in the yard. This piping is 30 inches outside diameter (OD) within the containment, 32 inches OD within the penetrations, 32 inches OD inside the penetration areas (except 34 inches OD from the safety valve headers) and 32 inches OD from the MSIVs to the mixing bottle. The mixing bottle has an OD of 43 inches.*

Following temperature and pressure equalization in the mixing bottle, steam is carried to the turbine by two parallel 40-inch OD pipes. Each of these pipes bifurcates to a pair of 28-inch lines which supply the four sets of turbine stop and governor control valves.

Equalization of steam pressure near the turbine is provided by a 24-inch OD pipe interconnecting the two main steam pipes just upstream of their respective bifurcations.

The exhaust from the high pressure turbine (cold reheat steam) is carried to six combination MSR assemblies. These assemblies have

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*All piping outside diameters (OD) given are nominal sizes.

horizontal cylindrical shells and are located alongside the LP turbine elements, three to a side. On each side of the turbine the cold reheat steam passes through two 44-inch OD pipes into a 62-inch OD pipe. The 62-inch pipes reduce to 54.5 inches and then 37.5 inches OD after feeding No. 1 and 2 MSRs respectively. The feed pipes to the No. 1 and 3 MSRs are 37.5-inches OD, while those to the No. 2 MSRs are 42-inch OD. The steam leaving each of the six MSRs is conveyed to its respective LP turbine element by a 37.5-inch OD pipe.

The Turbine Bypass System removes steam from the two 40-inch OD main steam pipes through two 16-inch OD pipes just upstream of the main steam line bifurcations. A portion (up to 40 percent of full load flow) of the steam thus removed can be routed to the condenser through six 12-inch OD pipes, each of which branches into two 10-inch OD pipes, while the remainder of this flow is used to feed the MSR main steam coils through six additional 10-inch OD pipes.

The main steam piping is in compliance with ANSI B31.1.0, and was designed using the appropriate wall thickness formula from the ASME Boiler and Pressure Vessel Code (1965 edition and summer addendum of 1966) with allowable stress values from ANSI B31.1.0.

The piping between the steam generators and the MSIVs outside the containment is designed to Seismic Category I criteria with materials quality governed by ANSI B31.7. The principal piping is rolled electric - fusion welded carbon steel, manufactured to ASTM Specification A155, Grade KC 70, Class I, or a substitutable chrome alloy or stainless steel material. A portion of the main steam piping replaced during the Steam Generator Replacement Project for Unit 1, uses ASME SA 672, Grade C70, Class 22 material. The entire system has been stress analyzed for the forces and moments resulting from thermal growth, and the piping upstream of the MSIVs has been dynamically analyzed for seismically induced stresses. The main steam piping within the containment has been analyzed to ascertain the effects of a guillotine rupture and restraints have been provided to ensure that such a rupture will not compromise containment integrity. Main steam piping at the safety and relief valves has been

or vent valve bodies will result in one of two consequences, either of which is considered acceptable:

1. If the pressure boundary failure is of such a size that steam leaks from above the piston at a rate greater than that which can be replenished through the equalizing orifice in the piston, the valve will close.

2. If the pressure boundary failure is of such a size that its leakage can be replenished by flow through the piston orifice, the valve will remain in its open position until closed by the appropriate isolation signal.

If the valve fails to close upon venting of the steam above the piston, the hydraulic operator may be used to close the valve.

10.3.2.3 Flow Limiters

Each steam line is provided with a venturi-type restrictor. The flow restrictors are designed to increase the margin to departure from nucleate boiling (DNB), and thereby reduce fuel clad damage, by limiting steam flow rate consequent to a steam line rupture and thereby reducing the cooldown rate of the primary system.

Design criteria for the steam line flow restrictors provide the following:

1. Provide plant protection in event of a steam line rupture downstream of the restrictor. In such an event, the flow restrictor reduces steam flow rate from the break, which in turn reduces the cooling rate of the primary system. This increases the margin to DNB and fuel clad damage, as shown in Section 15.

2. Minimize unrecovered pressure loss across the restrictor coincident with limiting accident flow rate to an acceptable value (less than 5 psi at 120 percent of rated steam flow).

Design requirements imposed in addition to the design criteria include the following:

1. Reduce thrust forces on the main steam piping in the event of a steam line rupture, thereby minimizing the potential for pipe whip.

2. Provide a portion of the pressure differential necessary for steam flow measurement.

3. Withstand the number of pressure and thermal cycles experienced in the life of the plant.

4. Maintain restrictor integrity in event of double-ended severance of a main steam line immediately downstream of the restrictor.

The location of the flow restrictors is shown on Figures 10.3-1A and B. Restrictors are positioned approximately 24 pipe diameters downstream of each steam generator in vertical sections of piping in order to minimize the length of piping preceding the restrictor, thereby reducing the probability of an upstream pipe break.

Each flow restrictor is provided with two steam flow transmitters which provide inputs to the Reactor Protection System. These transmitters have variable damping which is adjusted to minimize false safety injection signals caused by spurious transient high steam flow signals. The damping is selected so that the transmitter and protection channel response times do not exceed Technical Specification time response requirements and hence do not affect any safety margin.

All the statements above are applicable to both units. However, each Model-F steam generator also has an integral flow restricting device in the steam nozzle, with a flow area of 1.4 ft^2.

10.3.3 Evaluation

10.3.3.1 Transient Effects

A reactor trip from power requires subsequent removal of core stored and decay heat. Immediate heat removal requirements are normally satisfied by the steam bypass to the condensers and pressure relief system. Thereafter, core decay heat can be continuously dissipated as feedwater in the steam generator is converted to steam by heat absorption. The capability to return

and supply restraint against undesired motion. Where necessary, the valve operator has also been restrained to limit seismically induced motions.

10.3.4 Inspection and Testing Requirements

The MSIVs (MS167) and automatic drain stop valves (MS7) shall be tested periodically as set forth in the Technical Specifications.

The main steam drain traps are periodically tested to ascertain their proper functioning and, hence, prevent any unnecessary water accumulations.

Removable insulation panels have been provided at welds in the Main Steam System between the steam generator and the MSIVs in order to accommodate volumetric and surface weld examination as specified by periodic inservice inspection requirements.

A functional test of the turbine governor control valves is performed periodically and can be made while the unit is carrying load. The purpose of this test is to ensure proper operation of the turbine stop valves, control valves, reheat stop valves, and interceptor valves.

The controls and protective devices associated with system components, including steam generator safety valves, are tested as set forth in the Technical Specifications.

10.3.5 Water Chemistry

10.3.5.1 Chemical Feed System

The Chemical Feed System is shown on Figure 10.3-3. Chemical feed equipment is provided to add hydrazine and ammonium hydroxide and/or ethanolamine (ETA) which is an alternate amine to the discharge of each condensate pump. In addition, equipment is available to feed a solution of hydrazine and ammonium hydroxide to the inlet main and auxiliary feedwater line of each steam generator.

Hydrazine is added to the Condensate System and the main and auxiliary feedwater system for control of residual oxygen. Ammonium hydroxide and/or ethanolamine (ETA) which is an alternate amine is added for corrosion and pH control and minimizes metal pickup through the cycle.

The chemical solutions are prepared with demineralized water and stored in covered tanks. All chemicals are injected by motor-driven positive displacement pumps with both manual and/or automatic control.

10.3.5.2 Secondary Water Chemistry Control Program

The Secondary Water Chemistry Control Program is designed to limit the corrosion of the tubing and internals of the steam generators. The basis of the program is to control the levels of the critical parameters in the steam generator bulk water such that maximum protection to the steam generators is provided and tube integrity is maintained.

Protection of the steam generator tubing is accomplished by maintaining the water quality of the condensate and condensate polishing effluent and adjusting the blowdown on each of the four steam generators. The feedwater and steam generator bulk water treatment consists of introducing ammonium hydroxide and/or ethanolamine (ETA) which is an alternate amine for pH control and hydrazine for oxygen scavenging. This treatment is recommended by industry guidelines.

Steam Generator Blowdown Sample is measured for the following critical parameters: pH, cation conductivity, and sodium. The critical parameters measured at the condensate pump discharge include cation conductivity and sodium. The critical parameter measured at the condensate polishing effluent is total conductivity.

Steam Generator Blowdown Sample is analyzed in accordance with industry and vendor guidelines. Sampling frequencies and specifications may be found in the following industry and vendor guidelines: The EPRI PWR Secondary Water Chemistry Guidelines, INPO document 88-021, Westinghouse Technical Bulletin NISD-TB-85-12 and Westinghouse Report 83428. The sample frequency is increased when the normal control limits are exceeded to assure that operation is within the limiting specifications indicated in the above guidelines. The secondary system is monitored on a continuous basis with online chemistry monitors.

Out-of-specification chemistry is returned to within the normal limits of control within the times specified in the limiting specifications contained in the above guidelines. In the event that the limiting specifications cannot be maintained, a review is conducted by the Operations Manager who will initiate additional corrective actions (which can include removing the Unit from service if conditions warrant this course of action).

Should a condenser leak be confirmed, corrective actions will be taken to mitigate the leak in a time period consistent with its impact upon the Action Levels specified in the guidelines.

After a reactor turbine trip, the stored heat in the primary system is removed by the combination of steam dump to the condenser and atmospheric relief.

Should the condenser not be available as a heat sink, the steam generator safety valves and power operated relief valves (PORVs) will open to dump steam to the atmosphere. When the steam generator safety valves are reseated, the PORVs are used to remove residual heat and control steam pressure. The Auxiliary Feedwater System is used to maintain steam generator level.

The Steam Dump System also acts as a supplemental heat sink for a load reduction of up to 50-percent of rated load, including the 10-percent step load change capability of the NSSS, without a reactor trip.

Should a load drop in excess of 50 percent of full load occur, or should it be necessary to close the MSIVs with the plant under load, safety valve capacity equal to 100 percent of full load flow is provided on the piping just upstream of the MSIVs. This capacity is provided by five main steam safety valves on each main steam line with setpoints of 1070, 1100, 1110, 1120, and 1125 psig. The valves are located in the penetration area and are vented via umbrella-type vents to atmosphere through the roof of the penetration area.

Additionally, a power operated main steam relief valve (MSIO) is provided on each main steam line upstream of the MSIVs (total relief capacity for 4 valves equals 10 percent of full load flow). These valves, with a remotely variable pressure setpoint, can be used to bleed off reactor decay heat during cooldown.

10.4.4.2 System Evaluation

The atmospheric dump capacity of the steam generator safety valves is 100 percent of full load flow and the PORVs can pass an

additional 10 percent of full load flow. The number of turbine trips per year has been estimated to be 1.36, based on data from 60 plant-years of operating experience compiled by the Edison Electric Institute.

In the event that the PORVs in the secondary system failed to open when required, secondary system pressure would increase to the setpoint of the first of the five main steam safety valves. The five safety valves are set at 1070, 1100, 1110, 1120 and 1125 psig, respectively, and have a total relief capacity of 100 percent of full load flow to the atmosphere. The radiological consequences of this discharge to the atmosphere are calculated as described below.

The maximum postulated total steam release is 3,356,100 lb (1.52×10^9 g). The postulated amount of steam released in the first two hours is 654,600 lb (2.97×10^8 g). The maximum permitted concentration of specific activity in the secondary system is 0.10 µCi/g of dose equivalent I-131. The calculated offsite exposure from the postulated release to the atmosphere of secondary coolant equivalent to the amount of steam released in the first two hours due to a net load rejection with loss of offsite power is less than 1.5 rem to the thyroid (whole body doses are negligible). This was calculated from the equation:

$$\text{Dose(rem)} = C \times M \times B(t) \times X/Q \times DCF$$

where:

C = secondary coolant specific activity, 0.10 µCi/g

M = amount of steam released in the first two hours, 2.97×10^8 g

B(t) = breathing rate, 3.47×10^{-4} m^3/sec

X/Q = atmospheric dispersion factor, 1.30×10^{-4} sec/m^3

DCF = 1.08 rem/µCi dose equivalent I-131 inhaled

Anticipated secondary system iodine concentration is at least a factor of 10 less than the 0.10 μCi/g value used in the above calculation. Additionally, the "realistic estimate" atmospheric dispersion factor is 3.00×10^{-5} sec/m^3. Using the more realistic values for these parameters reduces the calculated thyroid exposure for this potential release path to less than 35 mrem.

The condenser air removal gas monitors and the steam generator blowdown liquid monitors are described in Section 11.2.3.1. These monitors can be checked for proper operation by means of a check source. The range of detection selected for these monitors is based on the anticipated range and maximum activity to be measured.

10.4.5 Circulating Water System

The Circulating Water System furnishes the main steam condenser with cooling water from the Delaware River and is shown on Figures 10.4-3A and B. The Circulating Water System is a separate entity apart from the seismically designed Service Water System, which is covered in Section 9.2.

10.4.5.1 System Description

The siphon recovery Circulating Water System supplies 1,110,000 gpm of Delaware River water to each unit's triple-shell condenser. The three condenser shells are single pass with divided waterbox circulation. Each condenser shell half is

185,000 gpm and 27-foot total dynamic head (TDH). Driven by 2000 hp induction motors, the six circulators per unit are mounted in individual pump cells in the intake structure, which is common to Units 1 and 2.

The circulating water pumps are powered from their respective unit's 4160-V circulating water distribution system. Remote control of all pumps is maintained by the operator in the respective unit's control room.

The 500-foot offshore circulating water system discharge is arranged to prevent recirculation while limiting the overall temperature rise of the river to 4°F or less in the vicinity of the outlet. The system is constructed of prestressed concrete, embedded steel cylinder pipe. Subaqueous piping is employed in the portion of the discharge piping submerged in the river. The inlet velocity to the intake screen wall is 1 fps at mean low tide which is compatible with local marine life. The intake includes 2-foot wide fish escape passages immediately in front of the traveling screens. The traveling water screens extend the full length and height of the 12-bay structure.

The circulating water pumps are of the pullout-type design to operate at the lowest recorded river elevation of 81.0 feet. All electrical components associated with the intake are mounted above the highest recorded water elevation for flood protection. An 8-foot high concrete wall is provided to protect the equipment from wave runup.

A full depth heavy duty trash rack is located at the entrance to each pump cell to protect the circulating pumps and traveling screens from damage by large debris. Two mobile mechanical rakes are included to remove debris from the face of the trash racks. Refuse pits with removable bins are provided at each end of the intake structure for collecting the debris raked off of the trash rack and traveling screens for offsite disposal.

Each circulating water pump is provided with a pump "READY TO START" circuit with associated pushbutton and "READY TO START" indicating light. Prior to a pump start, the "READY TO START" pushbutton is depressed. The "READY TO START" indicating light will flash while the pump permissives are being met and go solid when the pump is ready for starting. If the waterbox is under a vacuum of > 2.5" Hg vacuum then the "READY TO START" circuit will open the pump's associated waterbox vacuum breakers allowing the waterbox to fill with air and reduce the vacuum to < 1" Hg.

After the pump is started and

brought up to design speed, the valve in the condenser discharge line is opened, the pump bypass valve is then closed and full circulating water flow is established. The circulating water circuit for the associated pump is then primed by one of two mechanical vacuum pumps which ensure the waterboxes are full for plant operations. The above procedure should eliminate the hydraulic surges encountered with conventional startup practices. During normal operation, the condenser waterboxes are continuously vented to the vacuum pumps through float valves in order to effectively eliminate any accumulation of dissolved air released under siphon conditions.

Each circulating water circuit is equipped with quick opening vacuum breaker valves designed to admit air into the circuit in the event of a circulator trip out.

The arrangement of the circulating water intakes is shown on Figure 10.4-4. This area is served by temporary cranes, as required.

The circulating water intake contains vertical, turbine-type auxiliary service pumps which supply the traveling screen spray wash system. There are four pumps per unit, each with automatic strainers in their discharge line. Two bearing lubrication pumps and strainers provide river water to the circulating water pump bearing and motor coolers for each unit. A standby backup line from the screen wash header to the lubrication system is provided for use during emergency and/or maintenance situations.

10.4.5.2 Performance Analysis

All six circulating water pumps are normally in service. The condenser steam spaces are interconnected to permit operation with less than the full complement of circulating water pumps.

For performance analysis, the Circulating Water System is equipped with test connections to evaluate flow conditions. In addition,

the discharge pressure of each pump is monitored at the intake structure.

10.4.6 Condensate Polishing System

10.4.6.1 Design Bases

The Condensate Polishing System (CPS) was designed to perform the following functions:

1. Removes the low levels of dissolved solids present in the feedwater or secondary system and feedwater path. The CPS also acts as a high rate filter to remove suspended matter.

2. Provides the plant with a feedwater system cleanup capability. The CPS together with the Condensate Bypass System allows for the flushing of feedwater lines and recirculation back to the condenser during startup to ensure that the water quality is within specification prior to its admission to the steam generator. Heater drains may also be recycled back to the condenser to permit feedwater cleanup.

10.4.6.2 System Description

From the hotwells, condensate is directed through a full flow, high pressure, deep bed demineralizer CPS by three condensate pumps. The primary purpose of the polisher is to reduce, by ion exchange, the level of the dissolved solids in the Steam Generator Feed and Condensate System. The polishing system also filters out scale and particulate matter which may be present either as construction debris or as a result of corrosion products generated in the system.

The CPS is of the full flow, deep bed type and is designed to handle condensate at temperatures from 50°F to 130°F at pressures to 700 psig. Normal operating pressure will be about 475 psig.

The CPS is designed to handle a normal and a maximum continuous flow of 22,000 gpm and 24,000 gpm, respectively, with five of the six demineralizers operating in parallel.

A feedwater pH range of 8.8 - 9.6, is recommended for Salem with alternate amine chemistry (ethanolamine). While using ammonia only for pH control a range of 8.8 - 9.2 is recommended by EPRI. However, sodium levels in the feedwater become extremely critical in this pH range since sodium may be converted to sodium hydroxide. Sodium hydroxide, if carried over into the steam generators, will increase the possibility of caustic embrittlement of steel and stress corrosion cracking of Inconel components of the steam generator.

The operator is alerted to (partial) bypass of the CPS when valve 1(2)CN-109 is open and either valve 11(21)CN-108, 12(22)CN-108 or 13(23)CN-108 are not fully shut (valves are shown on Figures 10.4-5A and B).

10.4.7 Condensate and Feedwater Systems

10.4.7.1 Main Condensate and Feedwater System

10.4.7.1.1 System Description

The Steam Generator Feedwater and Condensate System is shown on Figures 10.4-5A and B. Condensate is withdrawn from the condenser hotwells through a common suction header by three motor-driven, multi-stage, vertical centrifugal condensate pumps rated at 8000 gpm and 575 psi TDH. These pumps discharge into a common header which carries the condensate into the first five stages of feedwater heating. A low flow recirculation line is provided on the discharge of each condensate pump to maintain a minimum flow of 1800 gpm for pump protection. The vertical motors are located at an elevation above the highest recorded river water level.

Two, one-half capacity, high speed, barrel-type feed pumps take suction from a common header receiving feedwater from the discharge of the No. 5 heater. These feed pumps discharge into a

common header, through the No. 6 high pressure feedwater heater and into a collecting header. Feedwater then flows through one line into the steam generator inlet header which is located outside the containment.

Feedwater enters the containment vessel through four lines penetrating the containment wall, one line feeding each steam generator. Feedwater flow control valve, motor-operated stop check valve, and isolation valves are installed in each steam generator feedwater line outside the containment. Each feedwater control valve is positioned by its own three-element control of feedwater flow to maintain steam generator level during startup and low power operation. All feedwater piping downstream from, and including, the isolating motor operated stop check valve is designed to meet Class I seismic requirements. A low flow recirculation line is provided on the discharge of each steam generator feed pump to maintain a minimum flow of 2300 gpm at design conditions for pump protection.

Each steam generator feed pump is designed for a capacity of 18,600 gpm and total developed head of 884 psi. These design conditions were based on the maximum calculated turbine load plus allowance for pump wear and steam generator blowdown.

Each steam generator feed pump is driven by a variable speed steam turbine with throttle steam supplied from the reheater outlet for normal two pump operation and from the Main Steam System during periods of low load. During startup, steam is supplied from the station heating steam system. Each steam generator feed pump turbine exhausts separately into one of the three condenser shells.

The Feedwater Heating System utilizes six stages of closed feedwater heaters. All feedwater heaters are horizontal "U" tube, one-third size units, (three strings) with each heater string capable of satisfactory operation at 150 percent of its design feedwater flow. The feedwater heaters and piping are arranged to

allow balanced turbine operation resulting from forced load limitation due to heater system outages. Bleed steam is provided from the following sources:

Heater No.	Extraction Source
6	High-pressure (HP) turbine bleed
5	HP turbine exhaust
4	Low-pressure (LP) turbine bleed
3	LP turbine bleed
2	LP turbine bleed
1	LP turbine bleed

Drains from the HP heater (No. 6) cascade to the preceding LP heater (No. 5) and then to drain tanks. Three heater drain pumps take suction from the drain tanks and discharge to the feed pump suction. Drains from the four LP heaters cascade in sequence to the condenser. The Bleed Steam and Heater Drains System is shown on Figures 10.4-6A and B.

Design parameters of equipment in the Main Condensate and Feedwater System are listed in Table 10.4-1. The design codes for feedwater piping are ANSI B31.1.0 (1967) (see also Section 3.6.5.3). The design code for the condensate system is as defined in Reference 7 utilizing reduced ANSI B31.1.0 (1967) code allowables.

The possible effects of a postulated rupture of a feedwater line have been minimized by judicious pipe routing and adequate pipe whip restraint.

To ensure their integrity, the main and auxiliary feedwater lines inside the containment (out to their respective isolation valves) were constructed with materials, fabrication, inspection, and quality control in accordance with Nuclear Class 1 standards.

Group bus undervoltage protection (68 percent of nominal) will automatically trip the condensate pump 4-kV breaker upon sensing an undervoltage (i.e., loss of voltage) condition on its respective 4-kV group bus (1E, 1F, 1G, and 1H) using 1/1 logic taken once.

10.4.7.1.2 Feedwater Piping Integrity

Feedring Modification - (Unit 2 only)

The Salem Station Unit 2 utilizes Westinghouse Series 51 steam generators which contained vented feedrings with bottom flow holes, as shown on Figure 10.4-7. The feedrings are located just below the moisture separators and have been shown to be susceptible to initiation of a steam-water slugging type of water hammer under certain operating conditions at other plants.

Design changes to the Salem steam generators have been made to incorporate the installation of J-tubes on the feedrings. This modification is identical to that installed in the Trojan Nuclear Plant (Docket No. 50-344) and similar to the modifications made at the Indian Point 2 facility (Docket No. 50-247). A simplified J-tube feedring configuration is shown on Figure 10.4-8, and isometric diagrams of feedwater piping to the Salem Unit 2 steam generators is shown on Figures 10.4-13 through 10.4-16. Several advantages are obtained with J-tubes. First, in normal operation, the feedring is filled with water. When this condition exists, there is no mechanism for initiation of water hammer in the feedring. The conventional feedring is only partially filled with water at low flow rates. Second, since the bottom holes are eliminated, turbulence due to water entering from the bottom during depressurization has been eliminated. Third, with the tubes on top, the large vented area makes it very difficult to trap a bubble of steam in the feedring. With a conventional feedring, as the steam generator level rises to cover the bottom holes, any steam inside would be trapped. As the steam condenses, depressurization occurs. With the J-tubes, the feedring fills first and this refilling or recovering will not cause a depressurization inside the feedring. Therefore, with J-tubes installed, there are no expected operating occurrences that would allow steam to become trapped in the feedring and feedwater piping following a drop in steam generator water level below the feedring.

Feedwater testing at the plant performed subsequent to the J-tube installation has shown that the modification has eliminated the potential for steam-water slugging initiated by auxiliary feedwater flow addition. Therefore, there would be no consequent pressure wave, and no forcing function for additional analysis is required.

Testing

A test was performed successfully during the startup of Unit 2 to demonstrate that the Feedwater System modifications have eliminated the potential for water hammer.

Feedring and J-Nozzle Modifications - (Unit 1 only)

The Model-F steam generators were designated for service at Seabrook Unit 2 originally. The steam generators were originally furnished with a carbon steel feedring and carbon steel J-nozzles installed on the top of the feedring. Service at Salem and other stations has shown that the carbon steel J-nozzles are subject to accelerated erosion and corrosion.

Design changes have been made and were implemented before the four steam generators were removed from the Seabrook site. The carbon steel J-nozzles were removed by mechanical machining operations, and new J-nozzle assemblies, similar to Unit 2, welded in place. The new J-nozzle design in made of Inconel with a transition sleeve of carbon steel that is shop welded and examined to assure the integrity of the dissimilar weld. The inlet side of the carbon steel transition sleeve is buttered with Inconel to reduce the potential of erosion. The new J-nozzle assemblies are re-installed by welding the carbon steel sleeve to the carbon steel feedring.

In normal operation, the feedring is filled with water. When this condition exists, there is no mechanism for initiation of water hammer. With the J-nozzles on top, the large vented area makes it very difficult to trap a bubble of steam in the feedring. Also, with the J-nozzles on top, the feedring fills first, and any refilling or recovering will not cause depressurization inside the feedring. Therefore, with the new J-nozzle installation, there are no expected operating occurrences that would allow steam to become trapped in the feedring and feedwater piping following a drop in steam generator water level below the feedring.

The feedring configuration is shown in Figure 10.4-8a. This is a typical arrangement and each steam generator has a slightly different arrangement of J-tubes. Isometric diagrams of feedwater piping to the Salem Unit 1 steam generators are shown in figures 10.4-9 through 10.4-12.

Feedwater Pipe Cracking

Circumferential cracks were found in Unit 1 feedwater piping as a result of inspections pursuant to I and E Bulletin 79-13. These cracks were evaluated by the Westinghouse Research Center where the cause was attributed to cyclic stress assisted or accompanied by corrosion. The detailed evaluation of this matter, including corrective action taken, is contained in a report transmitted

to the NRC by letter dated August 24, 1979. Action on Unit 2 is being taken as outlined in a letter dated September 18, 1979.

The Unit 1 modifications to address the feedwater pipe cracking involved a replacement of the reducers adjacent to the nozzles. These replacements were performed with essentially a replacement-in-kind approach. Subsequent inspections of the Unit 1 feedwater piping and steam generator feedwater nozzle thermal sleeves identified additional cracking at piping welds and flaw indications on the thermal sleeves. This cracking has been attributed to cyclic stresses resulting from stratification loads due to cold feedwater injection into hot steam generators. As described in Section 3.6.5.3, one piece flued forging pieces have been attached to the Unit 1 steam generator feedwater nozzles to minimize the potential for thermal fatigue cracking concerns at the nozzle and inlet pipe locations. The one piece design replaces the various fitting and fitting welds on the inlet piping thus eliminating the welds in the stratification zone. These forging pieces have integral thermal sleeves and are constructed of erosion/corrosion resistant materials to minimize the effects of erosion/corrosion on the existing steam generator thermal sleeves.

The circumferential location of the feedwater nozzles for the replacement Unit 1 steam generators differs by approximately 90° from the original design. The feedwater piping in the vicinity of the steam generators was rerouted to accommodate the new locations considering existing structural interferences and thermal stratification. There is no significant change to the likelihood of thermal stratification with the revised piping layout.

10.4.7.2 Auxiliary Feedwater System

10.4.7.2.1 Design Basis

The AFW System serves as a backup system for supplying feedwater to secondary side of the steam generators at times when the Main Feedwater System is not available. The AFW System is relied upon to prevent core damage and system overpressurization in the event of accidents such as a loss of normal feedwater or a secondary system pipe rupture, and to provide a means for plant cooldown.

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The AFW System is capable of functioning for extended periods, allowing time either to restore normal feedwater flow or to proceed with an orderly cooldown of the plant to design temperature of the Residual Heat Removal (RHR) System. The AFW System flow and the water supply capacity is sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown.

Provisions are made to limit or terminate auxiliary feedwater flow to the affected loop 1) in the case of feedwater line break to ensure adequate flow to the effective steam generators and 2) in the case of a steam line break inside containment, to also limit the containment pressure.

Plant conditions which form the basis for AFW System performance requirements are the following:

1. Loss of main feedwater transient (with and without offsite power)

2. Feedline rupture

3. Steamline rupture

4. Loss of all ac power

5. Loss-of-coolant accident (LOCA)

6. Plant cooldown

10.4.7.2.2 System Description

The AFW System, shown on Figures 10.4-17A and B, supplies water to the steam generators for reactor decay heat removal if the normal feedwater sources are unavailable due to loss of outside power or other malfunction. Each unit is equipped with one turbine-driven and two motor-driven auxiliary feed pumps. Steam for the

In addition, the concentration of salt in the bulk steam generator water is lwell below the solubility limit of sodium chloride throughout the range of temperatures encountered.

Therefore, no decrease in heat transfer capability due to the deposition of salt on the steam generator tube surfaces is expected.

Clogging of Steam Generator Flow Paths by Salt Accumulation

The concentration and solubility of sodium chloride indicate that the internals of the steam generator totally immersed in the bulk liquid phase would not be subject to salt precipitation and clogging. Similar consideration of the steel surfaces at the water/steam interface suggests that although some salt deposition is likely, the deposition will not be at a fixed boundary because of level changes caused by intermittent steam release via the PORVs. In addition, any rewetting will be carried out with water which has considerable salt solubilization capability. It is therefore unlikely that salt bridging will occur at the water/steam interface. Zones above this interface are not expected to become clogged with salt, since the evaporation purified the solvent phase. Thus any salt carried upward by liquid phase entrainment should be washed back down into the bulk liquid by relatively pure water (condensed steam).

Corrosion Effects of Salt

The corrosion of carbon steels in hot concentrated sodium chloride solutions is controlled by the metal alloying constituents, solution flow rate, oxygen concentration, temperature, and solution pH. Literature values for carbon steel corrosion rates at steam generator operating temperatures vary from 0.012 inch/week (3) to 0.21 inch/ week (4). Tests carried out on ASTM SA 285 Grade C steel, used by Westinghouse as a tube support plate material show that a corrosion rate of approximately 0.015 inch/week can be expected when this material is exposed to

concentrated sea water at 540°F (5). The ligament between the tube and flow hole in the Salem steam generators is 0.083 inch wide. Based upon these data, tube support plate corrosion must be expected. Other carbon steels present in the steam generator will also be corroded by the hot concentrated sea water. The condition of these carbon steel internals under hot standby conditions does not compromise the integrity of the primary to secondary steam generator boundary, since their function is to act as anti-vibration support or steam separation equipment during normal power operation.

Data generated in single tube model boiler tests performed by Westinghouse indicate that Inconel 600 will pit at about 0.005 inch/week in hot concentrated sea water environments. Corroborative information of this behavior is contained in Reference 6. Nominal tube wall thickness in the Salem steam generators is 0.050 inch. Thus only shallow tube wall penetration should be anticipated as a result of 36 hours of operation at hot standby with concentrated sea water in the steam generators. No perforation of tube wall is anticipated.

Conclusion

Both primary circuit integrity and heat removal capability would be maintained and no provisions are necessary to attenuate the effects of service water addition to the steam generators.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Basis

The Steam Generator Blowdown System is designed to be operable in all normal operating modes. During periods of primary to secondary leakage, operation is controlled to ensure compliance with effluent regulations. To accomplish this, two possible blowdown paths are provided: (1) a blowdown path which utilizes a conventional blowdown system that discharges the effluent to the chemical waste basin for neutralization and disposal; and (2) a

blowdown path which discharges the blowdown to condenser. Operating conditions dictate which path should be used.

10.4.8.2 System Design and Operation

The system flow diagram and operational logic are shown on Figures 10.4-18A and B and 10.4-19, respectively.

Operation of the Blowdown System is initiated remotely from the Control Room. The blowdown rate of each steam generator is indicated on and controlled from the main console.

During startup (as well as up to 20 percent power, if required) the blowdown is directed to the No. 12 (22) steam generator blowdown tank. As soon as possible once the unit is online, the blowdown is transferred to the No. 12 (22) condenser.

When blowdown is directed to the steam generator blowdown tank, a portion of the water, which is at saturated conditions, flashes to steam. The steam is vented to the atmosphere through a rooftop vent and the remaining water is gravity drained to the chemical waste basin. The water is treated and then discharged to the Delaware River through the Circulating Water System discharge lines. It is anticipated that this blowdown path will only be used intermittently at those times when condenser No. 12 (22) is not available.

If a steam generator should develop a primary to secondary leak in excess of the radiation monitor setpoint while the Blowdown System is discharging to the condenser No. 12(22) or the chemical waste basin, high radiation signal from any of the blowdown sample radiation monitors will close the isolation valves and terminate blowdown.

10.4.8.3 Design Evaluation

If a steam generator should develop a primary to secondary leak while the blowdown system is discharging to the condenser or the chemical waste basin, the blowdown radiation monitor will alarm. The radiological warning, alarm and isolation functions of the steam generator blowdown system are described in section 11.4. Steam generator water chemistry will be monitored to ensure chemistry conditions are maintained as described in section 10.3.5.2.

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10.4.9 References for Section 10.4

1. E.S. Rosenfeld to J.R. Gasperini, "Salem Units 1 and 2, Final Definition of AFW Flow Assumptions To Be Used In Fuel Upgrade/Margin Recovery Project and Steam Line Break Analyses," NFU-93-083, February 11, 1993.

2. E.S. Rosenfeld to J. Huckabee, "Salem Units 1 and 2, Steam Line Break Analyses Assumptions," NFU-93-303, May 28, 1993.

3. Potter and Tease, Corrosion Science Vol. 12, No. 4, April 1972.

4. Huijbregts, W. M., VGB Speiswassertagung 1970.

5. Wootton, M. J., Westinghouse Class 2 Research Report 77-IB6-DENTS-R1.

6. Roberts, D. J., et al., AEC Research and Development Report GA-9299.

7. PSE&G Report S-C-CN-MEE-1073, "Condensate System Design Pressure Reconciliation," Revision 1.

2. Radioactive chemical laboratory drains

3. Hot shower drains

4. Decontamination area drains

5. CVCS demineralizer regenerant solutions and spent resins

6. Sampling System

In addition, piping has been installed to direct potential fluid leakage from valves in the following systems to the LWS: Residual Heat Removal (RHR), Safety Injection (SIS), Containment Spray, CVCS, Sampling Systems. This design minimizes the spread of highly radioactive liquid throughout the plant in the event of postuated accidents.

Additionally, continuous releases from steam generator blowdown primary to secondary leakage below the setpoint of the steam generator blowdown radiation monitor are processed to the condenser or to the non-radioactive waste treatment system.

The LWS also collects and transfers liquids from the following sources directly to the CVCS, to the waste holdup tanks, or back to the refueling water storage tank (depending on fluid content) for processing:

1. Reactor coolant loops

2. Pressurizer relief tank

3. Reactor coolant pump secondary seals

4. Excess letdown (during startup)

5. Accumulators

6. Valve and reactor vessel flange leakoffs

7. Refueling canal drains

These liquids flow to the reactor coolant drain tank and are discharged either directly to the CVCS holdup tanks or to the waste holdup tanks by the reactor coolant drain pumps which are operated automatically by a level controller in the tank. These pumps also return water from the refueling canal and cavity to the refueling water storage tank. There is one reactor coolant drain tank with two reactor coolant drain tank pumps located inside containment.

Where possible, waste liquids drain to the waste holdup tanks by gravity flow. Other waste liquids drain to the Auxiliary Building sump tank and are discharged to the waste holdup tanks by pumps operated automatically by a level controller for the Auxiliary Building sump tank.

With the exception of the shared pumps and tanks of the Laundry and Hot Shower Drains, the Chemical Drains, Portable Filter and the Portable Demineralizer, each unit has its own Liquid Waste Disposal System. The Laundry and Hot Shower Drain Tanks and the Chemical Drain Tank are pumped to one of the Waste Hold-up Tanks or the Waste Monitor Hold-up Tank of either unit.

When a Waste Hold-up or Waste Monitor Hold-up Tank is filled, it is isolated and sampled while another tank is in service. If analysis confirms that the activity level of the tank's contents is suitable for discharge, the tank's contents may be pumped through a flow meter and a radiation monitor to the Service Water System. Tanks requiring processing before release are routed on a batch basis through a portable filter and portable demineralizer. The effluent of the portable system is returned either to the Waste Monitor Hold-up Tanks or the CVCS Monitor Tanks to be sampled, analyzed, and either reprocessed or pumped through a flow meter and a radiation monitor to the Service Water System.

Although the Waste Monitor Hold-up or CVCS Monitor Tank analysis forms the basis for recording activity releases, the radiation monitor provides surveillance over the operation by closing the discharge valve if the liquid activity exceeds a preset value.

The waste evaporator is capable of producing distillate at a rate of 16.5 gpm. A reagent tank is provided on the evaporator inlet for the introduction of chemical additives to suppress foaming and regulate pH. Distillate produced by the evaporator is continuously pumped to the waste monitor hold-up tanks or the CVCS monitor tanks.

The evaporator DF (defined as waste inlet concentration/distillate concentration) is 1×10^4.

Piping and Valves

Piping and valves which are in contact with liquid wastes are constructed of stainless steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance. Isolation valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay. Relief valves are provided for tanks containing radioactive wastes if the tanks might be over pressurized by improper operation or component malfunction.

Spent Resin Storage Tank

The spent resin storage tank retains the spent resin normally discharged from the mixed bed, evaporator feed ion exchange, spent fuel pit, and cation demineralizers. A layer of water is maintained over the resin storage to prevent resin degradation due to heat generation from decaying fission products. The contents can be removed any time by flushing with nitrogen. Resin sample connections are supplied upstream and downstream of the spent resin storage tank isolation valve. The tank is all welded austenitic stainless steel.

Waste Monitor and Waste Monitor Holdup Tanks

The Waste Monitor Tanks have been disabled and left in place. These tanks are of welded stainless steel construction.

The Waste Monitor Hold-up Tank is also a welded stainless steel tank and it serves a dual purpose. Its normal function is as a third waste holdup tank to receive abnormally large quantities of waste discharged to the system, but it can also serve as a waste monitor tank.

Portable Demineralizer

Permanent provisions have been made to the waste liquid piping, compressed air piping, and the demineralized water-restricted area piping to allow for the installation and operation of a portable system to assist processing liquid radwaste from either unit. The Unit 2 liquid waste may be processed at a higher rate due to a difference in piping configuration. The system is installed and operated in the 103' elevation of the truck bay of the Auxiliary Building. The effluent of the portable system is returned to either the Waste Monitor Holdup Tanks or the CVCS Monitor Tanks to be sampled, analyzed, and either reprocessed or disposed of. Exhausted ion exchange media is transferred to a burial site approved container after which it can be processed, classified, and shipped for disposal.

Portable Filter

Permanent provisions have been made in the demineralized water and 460 vac supply to allow for the installation and operation of a portable filtration system to assist processing liquid radwaste from either unit. The system is installed and operated in the 100' elevation of the truck bay of the Auxiliary Building. The permeate from the portable system is sent to the portable demineralizers, in place of the unprocessed liquid radwaste. If the filtration system is bypassed liquid radwaste is processed only by the portable demineralizer as described above.

Steam Generator Blowdown

The steam generator blowdown system is described in section 10.4.8.

11.2.4 Operating Procedures

Verification is made to ensure that dilution flow sufficient to meet the requirements of 10CFR20 is available whenever radioactive liquid wastes are released to the Plant Discharge System.

Liquid waste releases are continuously monitored for gross activity during discharges to ensure that the activity limits specified in 10CFR20 for unrestricted areas are not exceeded. The maximum allowable release at the plant is specified in the Technical Specifications.

Radioactive liquid batch wastes are sampled prior to releases to the Plant Discharge System and records of all releases are kept.

Continuous releases from the steam generator blowdown system are monitored and controlled in accordance with the Salem Offsite Dose Calculation Manual.

11.2.5 Performance Tests

Samples are taken on each batch of liquid waste released. Station records contain the quantity and concentration of radioactive isotopes, the volume of each batch and estimates of the water flow for dilution. Each sample is analyzed for principal gamma emitters. Composites are prepared from each batch released during a month and analyzed for the principal gamma emitting nuclides, fission and activation products, gross alpha, and tritium. A quarterly composite analysis is also performed for Sr-89, Sr-90, and Fe-55. The sensitivities and frequencies of analyses comply with the requirements of Salem Technical Specifications.

Continuous releases from the steam generator blowdown system are sampled and analyzed to determine the quantity and concentration of isotopes present in the blowdown stream. Composites are prepared from the samples. The sensitivities and frequencies of analysis comply with the requirements of the Salem Technical Specifications.

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11.2.6 Estimated Releases

Liquid wastes are generated primarily by plant maintenance and service operations, and, consequently, the quantities and activity concentrations of influents to the system. Tables 11.2-5 and 11.2-6 are estimated values. Therefore, considerable operational margin has been assigned between the design capability and the estimated system load as indicated in Table 11.2-5. A conservative estimate of system ability to limit dissolved and suspended activity released in the liquid phase is summarized in Table 11.2-6: This tabulation is based on the following assumptions.

1. Fission product concentration in the reactor coolant is based on 1 percent defective fuel.

2. Non-recycleable leakage of reactor grade coolant which is processed and discharged from the plant is assumed to be a total of 2,102 gallons per day.

3. Non-reactor grade non-radioactive liquid leakage which is processed and discharged from the plant is assumed to be a total of 4,308 gallons per day.

4. It is assumed that the liquid wastes are accumulated in the waste holdup tank for a period of 10 days and then processed for discharge overboard with the raw cooling water.

5. A dilution factor is used in determining the discharge concentrations of liquids released from the waste monitor holdup and waste holdup tanks. This is discussed in Section 11.2.8.

6. The tritium that is formed in the fuel (the predominant source) diffuses through the zircaloy clad and eventually becomes available for dispersal to the environment. The expected release of ternary produced tritium is about 1 percent; the total annual tritium release expected is indicated in Table 11.2-6. All of the sources of tritium accumulating in the reactor coolant, shown in Section 11.1, are included in the annual release.

The release estimates given in Table 11.2-6 are based on continuous operation with 1 percent fuel defects in both units. Based on experience with operating pressurized water reactors to date, 0.2 percent is a more realistic estimate of fuel defects averaged over a year of operation. Hence, in order to evaluate expected releases, all release values, except for H-3 and corrosion activation products given in Table 11.3-6, could be reduced by a factor of 5.

The release estimates for continuous releases from the steam generator blowdown system are based on assumptions consistent with NUREG-0017. Releases are monitored by the steam generator radiation monitors which provide a signal to close the isolation valves to maintain releases within the requirements of the ODCM. At higher primary system activity levels, steam generator blowdown would be isolated at lower primary to secondary leakage rates.

11.2.7 Release Points

Release points are shown on the system flow diagram, Figures 11.2-1A and B.

11.2.8 Dilution Factors

Monitored waste released from the Liquid Waste Disposal System is normally pumped into the Circulating Water System discharge lines via the Service Water System. The maximum release rates are calculated based on how many circulators are available in the release path. The release rate is controlled by throttling the discharge valve to maintain the maximum release rate or less.

Steam generator blowdown is directed to the non radioactive waste basin either from the blowdown flashtank or from the condensate polishing system and then to the circulating water system.

Dose due to H-3

$$D = 51(4.5\times 10^{-7}\frac{uCi}{cc})\ (1\ \frac{cc}{gm})(0.0057\frac{Mev}{dis})(200\frac{hrs}{yr})(\frac{1\ day}{24\ hrs})$$

$$D = 1.1\times 10^{-6}\frac{rads}{yr}$$

The total dose is thus 1.1×10^{-6} rads per year.

The dose to an individual fishing along the shore or on a boat on the river can be estimated in a manner similar to the one above. In this case, it is more appropriate to think in terms of a "semi-infinite" medium, since essentially no radioactivity from releases to the river is present in the air above the river (in the swimming case, it was assumed that the individual was "submerged" in the water; hence, the individual would be exposed to radiation from all directions).

The doses to an individual fishing 200 hours per year on shore or on a boat would thus be one-half of the doses previously calculated, or 4.3×10^{-9} rads per year due to all isotopes except H-3 and 5.5×10^{-7} rads per year due to H-3, for a total dose of 5.5×10^{-7} rads per year.

The dose pathways considered, and the resulting doses to the maximally exposed individual based on realistic liquid releases at 0.2 percent failed fuel defects, are summarized in Table 11.2-9.

Doses and releases, including steam generator blowdown continuous releases are controlled in accordance with the Salem Offsite Dose Calculation Manual.

11.2.10 Reference for Section 11.2

1. Evans, R. D. "The Atomic Nucleus," McGraw-Hill, 1955, p. 742.

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11.4.3 Sampling

Samples are taken as required by the plant Technical Specifications. The plant vent will be continuously monitored for gross radioactivity. Additionally, a fixed paper particulate filter followed by a charcoal cartridge (Cesco or equivalent) is installed, both of which will be changed weekly. The charcoal cartridge and particulate filter will be analyzed by gamma spectroscopy within 48 hours from change out. A sample will be taken manually at a frequency not to exceed monthly, and an isotopic analysis performed to determine the identity and quantity of noble gases.

The sample will be taken at a time when there are no gas decay tank releases or containment purges in progress, since these releases are not representative of a continuous release. Therefore, gas decay tank releases and containment purges will be analyzed isotopically on a batch basis.

The method employed will be a grab sample, utilizing a gas collection device, taken from either of two sampling points in the plant vent. These samplers are the same as those used in conjunction with the continuous plant vent gas monitors outlined in Section 11.4.2.2.

In order to ensure that the inline filter and cartridge sample is representative of the plant vent exhaust gas, a weekly isotopic analysis of the particulate filter and cartridge is performed. This isotopic inventory is used to determine the isotopic composition of the plant effluent. In the event that this equilibrium is upset by a refueling, process change, or a deviation of greater than 20 percent in the isotopic ratio established from the previous isotopic analysis (this does not apply while releasing gas decay tanks or during containment purging), a new isotopic analysis will be performed.

In order to ensure sampling during a radiological emergency that might render the normal plant vent sampling station uninhabitable, a supplemental Plant Vent Sampling System is provided. The supplemental Plant Vent Sampling System is located in a region of the plant that is expected to be habitable during all accident conditions (west side of the Fuel Handling Building). The supplemental system is designed such that it can be used during normal or accident conditions. The sample lines are heat traced to help ensure that a representative sample is being delivered to the supplemental sampling station.

The controlled facilities ventilation duct is equipped with offline particulate and iodine samples that operate in parallel with its system operation. The cartridges are removed and analyzed whenever necessary.

Samples are taken on each batch of liquid waste released. Station records contain the quantity and concentration of radioactive isotopes, the volume of each batch and estimates of the water flow for dilution. Each sample is analyzed for principal gamma emitters. Composites are prepared from each batch released during a month and analyzed for the principal gamma emitting nuclides, fission and activation products, gross alpha, and tritium. A quarterly composite analysis is also performed for Sr-89, Sr-90 and Fe-55. The sensitivities and frequencies of analyses comply with the requirements of Salem Technical Specifications.

Information on sampling of the containment atmosphere and the Reactor Coolant System is included in Section 9.3.

All activities of unloading, inspecting, moving, removing, and replacing the fuel assemblies will be performed in accordance with written procedures.

Assemblies will not be handled during severe weather conditions; for example, during periods when a hurricane or tornado watch is in effect in the vicinity of the site.

A Geiger-Mueller, or equivalent, monitor is located on the operating deck floor (Elevation 130 feet) of each Fuel Handling Building. These monitors are sensitive to gamma radiation and are alarmed in accordance with NRC Regulation 10CFR70.24. The alarm will sound locally and in the Control Room.

In addition, personnel authorized to enter the Fuel Handling Building shall carry personnel radiation monitoring devices. Radiation monitoring of the facility area shall be conducted on a routine basis, and portable radiation survey instruments shall be used during all fuel handling operations.

Comprehensive emergency procedures have been written to ensure that all personnel withdraw upon the sounding of the alarm to a designated area of safety. Procedures are approved by the Vice President Operations and include provisions for instruction of personnel and conduct of drills to familiarize them with the evacuation plan. Portable radiation survey meters are in accessible locations for use in such an emergency.

Before the receipt of new fuel, all personnel associated with the fuel handling operation will have received training in Health Physics and fuel handling procedures.

12.1.4 Area Monitoring and Radiation Surveys

The primary purpose of the area monitors is to prevent excessive personnel exposure by monitoring locations within the plant. A secondary purpose is for emergency response assessment and to provide radiation data in support of the as low as is reasonably achievable (ALARA) program and Regulatory Guide 8.8. Area monitors are located in the station radiologically controlled area where dose rates may be used to indicate potentially degrading plant conditions. The monitors provide local indication and alarms and operate horns and flashing beacons upon high radiation conditions. Control Room indications and alarms are also provided. The area monitoring system is described in Section 11.4. Onsite areas external to plant buildings are monitored by thermoluminescent dosimeters.

Radiation surveys are conducted to identify and control radiation sources associated with the operation of the Salem station. They are also performed to mark and verify radiation area boundaries, and to determine if abnormal radiation levels exist. The location and frequency of these routine radiation surveys are defined in the station Radiation Protection procedures. Radiation, High Radiation, and Very High Radiation Areas are posted conspicuously to ensure compliance with 10CFR20. Radiation survey instruments are calibrated using current industry standards and guidelines.

12.1.5 Estimates of Exposure

The average annual onsite person-rem exposure resulting from plant operations is approximately 409 person-rem per year for Unit 1. This is based on operational data from 1976 through 1982 with values ranging from a low of 117 person-rem in 1977 to a high of 1027 person-rem in 1982, which included two refueling outages.

The average annual onsite person-rem exposure resulting from plant operations is approximately 16 person-rem per year for Unit 2. This is based on data for 1981-1982, during which time no major outages occurred.

Annual dose goals based on scheduled maintenance and/or refueling activities are established by station management.

12.3 RADIATION PROTECTION PROGRAM

12.3.1 Program Objectives

The Radiation Protection Program is designed to protect the general public and plant personnel from unnecessary exposure to radiation and radioactive materials. The program is aimed at preventing non-stochastic effects, limiting the probability of stochastic effects to acceptable levels, and ensuring that radiation exposures are justified. Compliance with current regulations ensures that the program achieves and maintains appropriately safe conditions for activities involving radiation exposure to individuals.

12.3.2 Organization

The Vice President - Operations has ultimate responsibility at the station level for the establishment and execution of the station Radiation Protection Program. Through the Radiation Protection Department, the Vice President - Operations implements the program to meet the requirements of 10CFR20, Regulatory Guides, and the Technical Specifications.

The Radiation Protection (RP) Manager is responsible to the Vice President - Operations and is responsible to manage the Radiation Protection Dept to meet station operational needs and radiological safety standards. At a minimum, the RP Superintendent shall meet or exceed the qualifications of Regulatory Guide 1.8 Revision 1-R. Each member of the RP facility staff shall meet or exceed the qualification requirements set forth in ANSI N18.1-1971. The duties and responsibilities of the RP Superintendent include the following:

1. Manage and administer the station Radiation Protection program to ensure exposure to personnel are ALARA in accordance with applicable federal and state regulations.

2. Manage, control and administer the station radioactive material control program to control the release of radioactive material.

3. Provide oversight for the Radiation Protection Training Program.

4. Administer and implement the Respiratory Protection and Engineering Controls Program to minimize airborne radioactive material to personnel.

5. Manage, control and administer the packaging and shipping of radioactive waste.

12.4 ALARA PROGRAM

PSE&G and its management are committed to operating the Salem Generating Station in a manner that will provide radiation protection for their employees, contractors, and the public. The ALARA program instituted by this commitment will set radiation exposure standards at the station well within federal regulatory limits. Training emphasizes the company commitment to the ALARA philosophy and the individual's responsibilities to that philosophy.

The Chief Nuclear Officer and President - Nuclear Business Unit has the corporate responsibility for establishing the ALARA program. The responsibility for coordination and administration of the corporate ALARA program is delegated by the Senior Vice President - Nuclear Operations to the Radiation Protection Manager (RPM) must ensure that the policies and commitments contained in the PSE&G ALARA program are properly implemented.

The RPM ensures proper implementation of the NBU ALARA Program by:

1. Developing policies for the NBU ALARA Program.

2. Ensuring radiation protection policies support the NBU ALARA Program.

3. Ensuring periodic reviews of the ALARA Program are conducted.

4. Reviewing the effectiveness of radiation protection and ALARA training programs.

The Vice President - Operations is responsible for ensuring the support of all station personnel for the ALARA program and directs the development of administrative and operating procedures designed to guide personnel in maintaining their exposures ALARA.

The ALARA program is supported by the Radiation Protection Manager. The Radiation Protection Manager's major ALARA responsibilities include:

1. Reviews of design changes for facilities and equipment that can affect radiation exposures;

2. Identifying location, operations, and conditions that have the potential for causing significant exposures to radiation;

3. Assisting station management in the establishment of person-rem goals;

4. Reviewing applicable station departmental procedures to maintain exposures ALARA;

5. Tracking exposures of station personnel by specific job functions and type of work.