FENOC
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Beaver Valley Power Station
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July 24, 2000
L-00-097

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit No. 1
Docket No. 50-334, License No. DPR-66
Updated Final Safety Analysis Report
Revision 18, January 2000

This letter forwards a signed original and ten (10) copies of Revision 18 replacement pages for the Beaver Valley Power Station, Unit No. 1 Updated Final Safety Analysis Report (UFSAR). The submittal reflects changes to the facility and procedures as described in the UFSAR that were completed during the annual reporting period ending January 22, 2000. Changes completed after the reporting period may also be included.

To the best of our judgment and belief, this revision accurately presents changes made since the previous submittal which are necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirements. This revision includes:

- Changes identified in the annual "Report of Facility Changes, Tests and Experiments." This report is submitted separately under the provisions of 10 CFR 50.59.

- Changes resulting from license amendments or to reflect NRC Orders.

- Changes to the quality assurance program which were made under the provisions of 10 CFR 50.54.

- Changes permitted by Regulatory Guide 1.181 that are not required to be submitted to the Commission through other reporting means. These are described on Attachment 1.

- Editorial changes intended to correct or clarify the text and figures of the UFSAR.

A053 1/11

If you have any questions concerning the attached, please contact Mr. Thomas S. Cosgrove, Manager, Licensing at 724-682-5203.

Sincerely,

Lew W. Myers

c: Mr. D. S. Collins, Project Manager
Mr. D. M. Kern, Sr. Resident Inspector
Mr. H. J. Miller, NRC Region I Administrator
Ms. M. E. O'Reilly (FirstEnergy Legal Department)

bc: w/o attachments

OSC Members

ATTACHMENT 1
INFORMATION REMOVED FROM THE UFSAR

1-17-25

This change removed excessively detailed information regarding available component cooling water surge tank capacity in gallons. The statement was revised to indicate that the tank capacity is sufficient to accommodate minor system surges and thermal swell.

1-17-30

This change removed excessively detailed information regarding the modulus of elasticity used in the design of the containment system.

1-17-34

This change clarified the description of component cooling water system tests and added a reference to Technical Specifications for test requirements.

1-17-41

This change removes information regarding river water pump capacity and power supply that is addressed elsewhere in the UFSAR.

1-17-43

This change clarifies the discussion of adjustment of boron recovery system setpoints for automatic system operation.

1-17-48

This change deletes reference to control rod shutdown banks in a statement indicating that rod speed can be varied. Other UFSAR text indicates that these banks are moved at constant speed.

1-17-53

This change clarifies the discussion of containment interior loading evaluation for steam generator cubicles by making reference to UFSAR figures showing pressure transient curves.

1-17-67

This change replaced Steam Generator Blowdown figures with a simplified schematic and revised references to the figures.

1-17-77

This change clarified the description of cooling water available to the containment air recirculation system and control rod drive mechanism cooling coils and deleted excessively detailed information.

1-17-79

This change clarified the description of safety injection accumulator isolation valve control circuitry.

1-17-86

This change replaced a paragraph and table describing seismic qualification of equipment with an updated discussion of seismic qualification commitments and related NRC safety evaluation reports.

1-17-87

Administrative changes were made to provide clarification of safety analysis report statements. The statements involved 1) pressurization of reactor coolant loop stop valve discs (pressurized during outages to minimize seat leakage), 2) reference to the quality assurance program description for quality standards applied to equipment employed with the Boron Injection Tank, 3) environmental qualification of motors for valves located inside containment which must operate during and or following the LOCA, and 4) an editorial change.

1-17-95

The change indicated that flood door seal air vessels would be recharged instead of replaced when the pressure falls to 100 psig.

1-17-97

The discussion of safety related cables inside containment was revised to indicate that any splices or modifications to this cabling will be installed in accordance with approved procedures to minimize the possibility of fires, and to meet environmental qualification requirements.

1-17-101

References to Shippingport Atomic Power Station were deleted or revised since the power station has been decommissioned.

1-17-102

This change indicates that the fuel pool tell-tale drains receiver is pumped into the decontamination building sump instead of one of the auxiliary building sumps.

1-17-109

A sentence was added to the discussion of reactor coolant pressure boundary leakage detection. The sentence states that a response time of four hours is consistent with the guidance of NRC Generic Letter 84-04.

1-17-126

This change added a clarification to Table 11.3-2, Process and Effluent Radiological Monitoring System, stating that the reactor coolant letdown low range channel can be configured as a high range or low range monitor.

1-17-131

Sample System Figures and references to these figures were deleted because they contained excessively detailed information.

1-17-132

Site Plan and Station Arrangement figures were replaced with a simplified schematic. References to these figures were updated to reflect the change.

1-17-133

Figures showing symbols and abbreviations for detailed piping diagrams were replaced with a figure showing symbols and abbreviations for simplified flow diagrams. References to these figures were also updated.

1-17-135

This change deleted Vent and Drain System figures. The figures were determined to contain excessively detailed information. References to these figures were also deleted.

1-17-138

This change revised the description of refueling water storage tank volume to consistently indicate that the tank has a maximum volume of approximately 441,000 gallons, and to reference Technical Specifications for the normal operating tank volume range.

1-17-140

Section 15 figures showing the Station and Instrument Air Systems, Component Cooling Water System, and Reactor Coolant System, were deleted. Other UFSAR changes provided simplified system drawings showing these four systems. The Section 15 Auxiliary Steam System figure was also deleted. It was determined that the Auxiliary Steam System figure provided excessively detailed information. References to these Section 15 figures were also updated to reflect the changes.

1-17-141

This change replaced the Main Steam System figure with a simplified schematic. The references to the figure were also updated.

1-17-143

This change replaced the Main Feedwater System figure with a simplified schematic.

1-17-145

This change replaced the Circulating Water System figure with a simplified schematic. Reference to this figure was also corrected to reflect the new figure number.

1-17-148

This change deleted the Auxiliary Steam and Air Removal figure in safety analysis report Section 10 and text references to the figure on the basis that this figure provided excessively detailed information.

1-17-150

Gaseous Waste Disposal System figures were consolidated to form a simplified schematic. References to these figures were also updated.

1-17-151

Liquid Waste Disposal System figures were simplified and consolidated to form a simplified schematic. References to these figures were also updated.

1-17-152

Solid Waste Disposal and Solid Waste Decontamination System figures were simplified and consolidated to form a simplified schematic. References to these figures were also updated.

1-17-153

Containment Ventilation Systems and Containment Vacuum and Leakage Monitoring System figures were simplified and consolidated to form a simplified schematic. References to these figures were also updated.

1-17-154

Reactor Coolant System figures were simplified and consolidated to form a simplified schematic. References to these figures were also updated.

1-17-156

Figures for Containment Depressurization Systems were replaced with a simplified schematic and references to these figures were updated.

1-17-157

This change deleted the Post DBA Hydrogen Analyzer System figures and the references to these figures since the figures contained excessively detailed information.

1-17-158

The Residual Heat Removal System figures were replaced with a simplified schematic.

1-17-159

The Fuel Pool Cooling and Purification System figures were replaced with a simplified schematic.

1-17-160

The Fire Protection - CO_2 System figure was replaced with a simplified schematic.

1-17-161

The Fire Protection - Halon and CO_2 System figure was replaced with a simplified schematic.

1-17-162

The figure showing the Fuel Oil System for Emergency Diesel Generators was replaced with a simplified schematic.

1-17-163

This administrative change revised a reactor coolant system design pressure setting (psig) value in Table 4.1-2, *Reactor Coolant System Design Pressure Settings*, to be consistent with the analytical value of record, and the value discussed in UFSAR Table 14D-3, *Trip Points and Time Delays To Trip Assumed In Accident Analyses.*

1-17-164

This change simplifies the Supplemental Leak Collection Release System figure and deletes the Charcoal Filter Assembly figure. The figures contained excessively detailed information. References to these figures were also updated to reflect the figure changes.

1-17-165

A statement describing SRO surveillance of all refueling operations was removed since a similar requirement is specified in the Technical Specifications.

1-17-167

This change deletes Auxiliary Building Arrangement, Solid Waste Disposal Area, Fuel and Decontamination Building Area, Diesel Generator Building Arrangement, Turbine Building Area Section, Station Arrangement Elevation, Radiation Monitoring System and Radiation Monitor Location figures, Main Steam and Feedwater Point Location figures, Main Steam and Feedwater Piping Restraint figures, Steam Generator Cubicle Loading

Diagram, Mathematical Model of 32 inch Pipe Whip Restraint figure, Fuel Transfer Tube Arrangement figure, Refueling Water Storage Tank Plan and Elevation figures, Pressurizer Sealed Reference Leg Level System and typical Reactor Coolant System Loop with Loop Stop Valve figures, Water Supply and Treatment Systems, Decontamination System, and Intake and Alternate Intake Structure Arrangement figures since they contained excessively detailed information. References to these figures were also revised to reflect the figure changes.

1-17-171

The description of compressed air systems was revised. The airflow capacity and compressor type specified for the Intake Structure Instrument Air System compressor was deleted. This information was determined to be excessive detail.

1-17-173

This change revised a statement regarding the receipt, possession and use of source, byproduct and special nuclear material to be consistent with the operating license.

1-17-174

This change replaces the UFSAR discussion of "environmental testing" that was conducted to support initial licensing of the station and Appendix D "Report on the Effect of a Piping System Break Outside Containment" with more recent commitments regarding environmental qualification of safety related electrical equipment.

1-17-175

Figure 2.1-7 shows the exclusion area boundary and gaseous release points. This change deleted Figure 2.1-7, deleted the text reference to the figure, and added a description of the release points to the text. The exclusion area boundary is shown on another UFSAR figure.

1-17-176

Figure 2.1-3, Local Site Topography, was revised to remove the Shippingport Atomic Power Station. The Shippingport Atomic Power Station has been decommissioned.

1-17-177

The UFSAR describes how emergency diesel generator fuel oil piping is protected from corrosion. This description was revised to allow an equivalent coating for buried fuel oil piping.

1-17-179

This change added a new Section 1.8.3 to identify safety analysis report sections that contain historical information.

1-17-180

The organization description section was revised to reference the Unit 2 safety analysis report for the design, construction, and operating phase organization. This will avoid the possibility of inconsistent or conflicting organization descriptions.

BEAVER VALLEY POWER STATION

UNIT 1, UPDATED FINAL SAFETY ANALYSIS REPORT

REVISION 18 INSERTION INSTRUCTIONS

Please remove pages and insert replacement pages as instructed below. Text and Figures are provided in separate packages.

REMOVE/INSERT Columns

Entries beginning with "T" designate table numbers. Entries beginning with "F" designate figure numbers. All other entries are page numbers. For example:

T1.7-1 (1 of 3)	=	Table 1.7-1, Page 1 of 3
F5.4-3	=	Figure 5.4-3
2.1-9	=	Page 2.1-9
vii	=	Page vii

Pages printed back to back on one sheet of paper are indicated by a "/". For example:

1.2-5/6	=	Page 1.2-5 backed by Page 1.2-6
1.8-7/Blank	=	Page 1.8-7 backed by a blank page

ALL VOLUMES

Note: 10 copies of the 2 pages listed below are provided in your package. One of each of these pages should be inserted in the front of each volume.

REMOVE	INSERT
i/Blank	Same
3/4	Same

VOLUME 1

Section 1

REMOVE	INSERT
1i/1ii and 1iii/1iv	Same
1-1/1-2 through 1-7/1-8	Same
1.1-3/4	Same

VOLUME 1

Section 1 (continued)

REMOVE	INSERT
1.2-1/2	Same
1.3-5/6	Same
1.3-35/36 and 1.3-37/38	Same
1.3-47/48 through 1.3-51/52	Same
1.7-1/2	Same
1.8-5/6	Same
1.8-7/Blank	1.8-7/1.8-8
F1.2-1	Same
F1.2-2	None
F1.2-3	Same
F1.2-4	None
F1.2-5	None
F1.2-6	None
F1.2-7	None
F1.2-8	None
F1.2-9	None
F1.2-10	None
F1.2-11	None
F1.2-12	None
F1.2-13	None
F1.2-14	None

VOLUME 1

Appendix 1A

REMOVE	INSERT
1A-23/24 and 1A-25/26	Same
1A-31/32	Same

VOLUME 1

Section 2

REMOVE	INSERT
2i/2ii through 2v/Blank	2i/2ii thru 2v/2vi
2-9/2-10	Same
2.1-1/2	Same
2.1-5/6 and 2.1-7/8	Same
2.1-29/30	Same
2.2-13/Blank	Same
2.3-3/4 through 2.3-9/10	Same
2.3-29/30	Same
2.5-5/6	Same
2.6-1/2 through 2.6-5/6	Same
2.7-13/14 and 2.7-15/16	Same
2.8-3/Blank	Same
F2.1-3	Same
F2.1-7	None

VOLUME 4

Section 3

REMOVE	INSERT
3i/3ii and 3iii/3iv	Same
3.1-1/2	Same
3.2-7/8 and 3.2-9/10	Same
3.3-15/16 through 3.3-19/20	Same
3.3-51/Blank	Same

VOLUME 4

Section 3 (continued)

REMOVE	INSERT
3.4-7/8	Same
3.4-15/16	Same
3.4-41/42	Same
T3.1-1 (2 of 5)	Same
T3.1-1 (3 of 5)	Same
T3.4-1 (2 of 3)	Same

VOLUME 4

Section 4

REMOVE	INSERT
4i/4ii and 4iii/Blank	Same
4-5/4-6	Same
4.1-1/2 through 4.1-7/8	Same
4.1-11/12	Same
4.1-17/18	Same
4.2-1/2	Same
4.2-11/12 through 4.2-15/16	Same
4.2-19/20 and 4.2-21/22	Same
4.2-25/26 and 4.2-27/Blank	Same
4.3-23/24	Same
4.5-3/4	Same
4.5-11/12	Same
T4.1-2 (1 of 1)	Same
T4.1-10 (1 of 2)	Same

VOLUME 4

Section 4 (continued)

REMOVE	INSERT
F4-1	None
F4-2	None
F4.1-1	Same
F4.2-1	Same
F4.5-2	Same
F4.5-6	None

VOLUME 5

Section 5

REMOVE	INSERT
5i/5ii through 5v/Blank	Same
5-3/5-4 through 5-7/5-8	Same
5.2-3/4 through 5.2-15/16	Same
5.2-53/54 through 5.2-61/62	Same
5.2-79/80	Same
5.3-5/6	Same
5.3-13/14 through 5.3-19/20	5.3-13/14 through 5.3-19/Blank
5.4-1/2	Same
5.4-9/10	Same
5.5-1/Blank	Same
5.6-3/4 and 5.6-5/6	Same
T5.2-15 (1 of 2)	Same
T5.2-15 (2 of 2)	Same
T5.3-1 (1 of 6)	Same
T5.3-1 (2 of 6)	Same
T5.3-1 (3 of 6)	Same
T5.3-1 (4 of 6)	Same
T5.3-1 (5 of 6)	Same
T5.3-1 (6 of 6)	Same

VOLUME 5

Section 5 (continued)

REMOVE	INSERT
T5.3-1A (1 of 12)	None
T5.3-1A (2 of 12)	None
T5.3-1A (3 of 12)	None
T5.3-1A (4 of 12)	None
T5.3-1A (5 of 12)	None
T5.3-1A (6 of 12)	None
T5.3-1A (7 of 12)	None
T5.3-1A (8 of 12)	None
T5.3-1A (9 of 12)	None
T5.3-1A (10 of 12)	None
T5.3-1A (11 of 12)	None
T5.3-1A (12 of 12)	None
F5.1-4	Same
F5.1-5	Same
F5.1-6	Same
F5.1-7	Same
F5.2-5	None
F5.2-29	None
F5.2-30	None
F5.2-31	None
F5.2-32	None
F5.2-33	None
F5.2-34	None
F5.2-35	None
F5.2-36	None
F5.2-37	None
F5.2-38	None
F5.2-39	None
F5.2-40	None
F5.2-56	None
F5.3-1	None
F5.4-1	Same
F5.4-2	None
F5.4-3	None
Notes for F5.4-3	None

VOLUME 5

Section 6

REMOVE	INSERT
6i/6ii and 6iii/6iv	Same
6-5/6-6	Same
6.2-3/4	Same
6.3-3/4 through 6.3-11/12	Same
6.3-19/20	Same
6.3-25/26 and 6.3-27/28	Same
6.3-33/34 through 6.3-39/Blank	6.3-33/34 through 6.3-37/38
6.4-1/2 through 6.4-11/12	Same
6.4-15/16	Same
6.5-1/2 and 6.5-3/4	Same
6.5-7/8	Same
6.6-1/2 and 6.6-3/4	Same
T6.3-3 (1 of 4)	Same
T6.3-3 (2 of 4)	Same
T6.3-3 (3 of 4)	Same
T6.3-3 (4 of 4)	Same
T6.3-9 (1 of 2)	T6.3-9 (1 of 1)
T6.3-9 (2 of 2)	None
T6.4-1 (4 of 4)	Same
F6.3-1	Same
F6.3-2	None
Notes for F6.3-1 & 6.3-2	None
F6.3-6	None
F6.3-8	Same
F6.3-9	Same
F6.4-1A	Same
F6.4-1B	Same
Notes for F6.4-1A & 6.4-1B	None
F6.4-5	None
F6.4-6	None
F6.4-7	None

VOLUME 5

Section 6 (continued)

REMOVE	INSERT
F6.5-1	None
F6.5-4	None
Notes for F6.5-1 & 6.5-4	None
F6.6-1A	F6.6-1
F6.6-1B	None
F6.6-2	None

VOLUME 5

Section 7

REMOVE	INSERT
7i/7ii and 7iii/7iv	Same
7-1/7-2	Same
7-5/7-6	Same
7.1-9/10	Same
7.2-5/6 through 7.2-9/10	Same
7.2-15/16	Same
7.2-25/26 and 7.2-27/28	Same
7.2-33/34	Same
7.3-3/4 through 7.3-15/16	Same
7.3-21/22	Same
7.3-25/26	Same
7.5-1/2	Same
7.5-5/Blank	7.5-5/6
7.6-1/2	Same
7.7-5/6 through 7.7-9/10	Same
7.7-13/14	Same

VOLUME 5

Section 7 (continued)

REMOVE	INSERT
7.7-23/24	Same
T7.1-3 (1 of 1)	T7.1-3 (Deleted)
T7.7-1 (1 of 13)	Same
T7.7-1 (2 of 13)	Same
F7.2-1, Sheet 2	Same
F7.2-1, Sheet 7	Same
F7.2-1, Sheet 12	Same
F7.2-4	None
F7.6-1	None

VOLUME 6

Section 8

REMOVE	INSERT
8i/8ii	Same
8.1-1/2	Same
8.2-1/2	Same
8.3-1/2	Same
8.4-3/4 through 8.4-7/8	Same
8.5-1/2 through 8.5-9/10	Same
8.5-15/16	Same
F8.1-1 (Sheet 1)	Same
F8.1-1 (Sheet 2)	Same
F8.3-1	Same
F8.4-1	Same
F8.4-2	Same

VOLUME 6

Section 9

REMOVE	INSERT
9i/9ii through 9v/vi	Same
9-1/9-2	Same
9-5/9-6 and 9-7/9-8	9-5/9-6 and 9-7/Blank
9.1-1/2 and 9.1-3/4	Same
9.1-15/16	Same
9.1-19/20	Same
9.2-1/2 through 9.2-5/6	Same
9.3-1/2 and 9.3-3/4	Same
9.4-1/2 through 9.4-17/Blank	9.4-1/2 through 9.4-13/Blank
9.5-3/4 through 9.5-9/10	Same
9.6-1/2 through 9.6-7/8	9.6-1/2 through 9.6-9/Blank
9.7-1/2	Same
9.8-1/2 and 9.8-3/4	Same
9.9-1/2 and 9.9-3/4	Same
9.9-9/10	Same
9.10-1/2	Same
9.10-5/6	Same
9.11-1/2	Same
9.12-1/2 through 9.12-7/8	Same
9.12-15/16	Same
9.13-3/4 and 9.13-5/6	Same
9.14-1/2	Same

VOLUME 6

Section 9 (continued)

REMOVE	INSERT
9.15-1/2	Same
9.16-1/2 and 9.16-3/4	Same
9.17-1/2	Same
T9.1-3 (1 of 3)	Same
T9.2-1 (2 of 11)	Same
T9.2-1 (4 of 11)	Same
T9.2-1 (9 of 11)	Same
T9.2-1 (10 of 11)	Same
T9.2-1 (11 of 11)	Same
T9.2-2 (6 of 6)	Same
T9.3-2 (1 of 1)	Same
T9.4-1 (1 of 2)	Same
T9.4-1 (2 of 2)	Same
T9.4-3 (1 of 1)	Same
T9.4-6 (1 of 1)	Same
T9.8-1 (1 of 2)	Same
T9.8-1 (2 of 2)	Same
T9.9-6 (1 of 1)	Same
T9.10-1 (1 of 3)	Same
T9.10-2 (1 of 1)	None
T9.17-1 (1 of 1)	Same
F9.1-1A	F9.1-1
F9.1-1B	None
F9.1-2	Same
F9.2-1	Same
F9.2-2	None
F9.2-3	None
F9.2-4	None
F9.3-1	Same
Notes for F9.3-1	None
F9.4-1	Same
F9.4-2	None
F9.4-3	None
F9.4-4	None
F9.5-1	Same
Notes for F9.5-1	None
F9.6-1	None
F9.6-2	None
F9.6-3A	None
F9.6-3B	None
F9.6-3C	None

VOLUME 6

Section 9 (continued)

REMOVE	INSERT
F9.6-4	None
F9.7-1	None
F9.7-2	None
F9.7-3	None
F9.8-1	Same
F9.8-2	None
F9.9-1A	F9.9-1
F9.9-1B	None
F9.9-1C	None
F9.9-1D	None
Notes for F9.9-1A thru 1D	None
F9.9-2	None
F9.9-3	None
F9.10-2	Same
F9.10-3	Same
F9.11-1	None
F9.13-3	Same
F9.14-1	Same
F9.15-1	None
F9.16-1	None
F9.16-2	None

VOLUME 6

Section 10

REMOVE	INSERT
10i/Blank	Same
10-3/10-4	Same
10.2-1/Blank	Same
10.3-1/2	Same
10.3-5/6	Same
10.3-9/10	Same
10.3-15/16 and 10.3-17/18	Same
10.3-21/22 through 10.3-27/28	Same

VOLUME 6

Section 10 (continued)

REMOVE	INSERT
F10.2-2	None
F10.2-3	None
F10.2-4	None
F10.2-5	None
F10.3-1	Same
F10.3-2	Same
F10.3-3A	F10.3-3
F10.3-3B	None
F10.3-4	Same
F10.3-5	Same
F10.3-6	Same
F10.3-7	None
F10.3-8	None

VOLUME 7

Section 11

REMOVE	INSERT
11i/11ii through 11v/Blank	11i/11ii thru 11v/11vi
11-7/11-8 and 11-9/Blank	Same
11.2-1/2 and 11.2-3/4	Same
11.2-7/8	Same
11.2-11/12	Same
11.2-15/16	Same
11.3-1/2	Same
11.3-7/8 and 11.3-9/10	Same
11.3-13/14	Same
11.3-21/22	Same
11.3-25/26	Same

VOLUME 7

Section 11 (continued)

REMOVE	INSERT
11.4-1/2 and 11.4-3/Blank	Same
11.5-1/2	Same
11.5-7/8 and 11.5-9/10	Same
11.5-13/14 through 11.5-17/18	Same
T11.1-1 (1 of 5)	Same
T11.1-1 (2 of 5)	Same
T11.1-1 (3 of 5)	Same
T11.1-1 (4 of 5)	Same
T11.1-1 (5 of 5)	Same
T11.3-1 (1 of 2)	Same
T11.3-1 (2 of 2)	Same
T11.3-2 (3 of 4)	Same
F11.2-1	Same
F11.2-2	None
F11.2-3	Same
F11.2-3A	None
F11.2-4	Same
F11.2-6	None
F11.2-7	None
F11.3-1	None
F11.3-2	None
F11.3-3	None
F11.3-4	None
F11.3-5	None
F11.3-6	None
F11.3-7	None
F11.3-8	None
F11.3-9	None
F11.3-10	None
F11.3-11	None
F11.3-12	None
F11.3-13	None
Notes for F11.3-9 thru F11.3-13	None

VOLUME 7

Section 12

REMOVE	INSERT
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FENOC

FirstEnergy Nuclear Operating Company

Beaver Valley Power Station, Unit 1

UPDATED FINAL SAFETY ANALYSIS REPORT

Revision 18 Replacement Pages

(Text and Tables)

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SECTION 1

INTRODUCTION AND SUMMARY

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* Note: Subsections 1.3.3.3 and 1.3.3.5 do not exist in the FSAR. Section 1.1.9 deleted by Updated FSAR, Revision 0.

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Appendix A describes the Quality Assurance program that is followed during all stages of station design, construction and operation. Appendix B describes the seismic design and analysis of structures, systems and components. All information in Appendix C has been deleted from the Updated FSAR, except for a reference to the Emergency Preparedness Plan for BVPS-1.

The AEC Regulatory Staff Questions and Positions raised during the AEC's review of the FSAR have been deleted as a separate section of the Updated FSAR and incorporated into appropriate sections of the Updated FSAR.

With respect to the numbers, graphs and drawings included within this report, it should be understood that normal tolerance permitted by good engineering practice is intended. Where operating parameters are unusually important, it is acknowledged that such items are included in the "Technical Specifications"; the adoption of which is a condition of the BVPS-1 Operating License. The engineering drawings in the Updated FSAR are not intended to accurately depict other than safety related equipment and systems. In any case, the latest revision of the appropriate approved and released engineering drawings should be consulted for the most current information, as the Updated FSAR is only current as of the date of submittal.

1.1.1 Design Highlights

The design of BVPS-1 was based upon proven concepts which were developed and successfully applied in the construction of other pressurized water reactor systems. In subsequent paragraphs, certain design features of BVPS-1 are indicated which represented slight variation or extrapolations from units which were approved for construction or operation such as the Surry Power Station Units 1 and 2 (Dockets 50-280 and 50-281), North Anna Power Station Units 1 and 2 (Dockets 50-338 and 50-339), Turkey Point Plant Units 3 and 4 (Dockets 50-250 and 50-251), and H. B. Robinson No. 2 (Docket 50-261). The comparison of BVPS-1 with other licensed plants was considered valid at the time of the issuance of the BVPS-1 Operating License.

1.1.2 Power Level

The initial nominal NSSS power rating for BVPS-1 is set at 2,660 MWt. Site and engineered safety evaluation is performed at the power levels specified in Section 14 for each particular accident. The maximum calculated rating of the turbine generator corresponds to the ultimate NSSS rating. The ultimate NSSS power rating is achieved by about a 4.3 percent increase in average reactor heat flux over that established for initial operation.

1.1.3 Reactor Coolant Loops

The reactor coolant system consists of three loops, each loop having components (steam generator, pumps, and piping) similar to those for the Surry Power Station Units 1 and 2, and including two reactor coolant loop stop valves and a bypass valve in each loop.

1.1.4 Peak Specific Power

The revised reactor core design is based on a maximum steady state peak specific power of 13.0 kw per ft for operation at 2,652 Mwt (NSSS 2,660 Mwt) and a corresponding peak power of 18.0 kw per ft for the maximum thermal overpower condition.

1.1.5 Fuel Clad

The fuel rod design for the reactor uses Zircaloy-4 as a clad material. Zircaloy-4 has proved successful in the CVTR and Saxton reactors and Yankee test assemblies, and was used in most Westinghouse reactors now in operation, under construction or currently being reviewed by the NRC.[2]

1.1.6 Fuel Assembly Design

The fuel assembly incorporates the rod cluster control concept in a canless 17 x 17 fuel and control rod array using Inconel spring clip grids to provide support for the fuel rods as used in the 15 x 15 assembly design. Extensive out-of-pile tests have been performed on this concept, successful in-pile tests have been performed in the Saxton reactor, and operating experience is available from the San Onofre and Connecticut-Yankee plants and other Westinghouse designed NSSS plants.

1.1.7 Moderator Temperature Coefficient of Reactivity

Burnable poison rods are used in the reactor unit to ensure a negative moderator temperature coefficient at hot shutdown temperature for initial startup. As the fuel in the core is depleted and the boron shim concentration is decreased, the moderator temperature becomes more negative.

1.1.8 Containment

The reactor containment concept is based upon the use of a reinforced concrete containment structure, similar to that of the Surry Power Station Units 1 and 2 and North Anna Power Station Units 1 and 2. The containment is maintained at subatmospheric pressure during normal operation. Following the postulated loss-of-coolant accident, described in Section 14.3, and the MSLB accident, described in Section 14.2, the containment peak pressure is reduced to subatmospheric by the use of the containment depressurization system, which contains redundant spray cooling systems, thereby positively terminating outleakage to the environment within 60 minutes after initiation of the accident. The adoption of subatmospheric containment results in reduced exclusion and population center distance requirements.

1.2 SUMMARY - STATION DESCRIPTION

1.2.1 General

BVPS-1 incorporates a closed-cycle pressurized water Nuclear Steam Supply System (NSSS), a turbine generator and their necessary auxiliaries. A radioactive waste disposal system, a fuel handling system, and all auxiliaries, structure and other onsite facilities required for a complete and operable nuclear power station are also provided. The general arrangement of BVPS-1 and the station arrangement are shown in the site plan, Figure 1.2-1.

Flow diagrams are included with the systems which are described throughout the Updated FSAR. Symbols and abbreviations used in these diagrams are illustrated in Figure 1.2-3.

Some equations in the FSAR are written in a modified FORTRAN type format. A description of this format is given in Table 1.2-1.

1.2.2 Site

The site comprising approximately 453 acres is located on the south bank of the Ohio River, in Beaver County, approximately 25 miles northwest of Pittsburgh. The exclusion radius is 2,000 ft. The nearest continuously occupied residence is located about 2,100 ft from the reactor. The Low Population Zone area distance is 3.6 miles. The population center distance is about five miles. The area is primarily agricultural, with some industrial activity.

1.2.3 Structures

The major structures are the containment structure, cooling tower, intake structure, auxiliary building, fuel building, decontamination building, turbine building, diesel generator building and service building which includes the main control area.

The containment structure is a steel-lined, reinforced concrete cylinder with a hemispherical dome and a flat reinforced concrete foundation mat. The containment which is designed to withstand the internal pressure resulting from the Design Basis Accident (DBA), meets all requirements for leak tightness at this pressure and provides adequate radiation shielding for both normal operation and accident conditions. There is no outleakage of activity from the containment structure when it is at subatmospheric pressure.

The seismic criteria used in the design of the structures and equipment for the station are described in Section 2.7.

1.2.4 Nuclear Steam Supply System

The NSSS consists of a pressurized water reactor, reactor coolant system and associated auxiliary systems. The reactor coolant system is arranged as three closed reactor coolant loops connected in parallel to the reactor vessel, each containing a reactor coolant pump, isolation and bypass valves, piping and a steam generator. An electrically heated pressurizer is connected to one of the loops on the reactor side of the loop isolation valves.

The reactor core includes uranium dioxide pellets, enclosed in Zircaloy tubes with welded end plugs, as fuel. The tubes are supported in assemblies by structures of spring clip grids and suitable end pieces for the support of the assembled rods and restraint of abnormal axial movement. The mechanical control rods consist of clusters of stainless steel clad absorber rods which are guided by tubes located within the fuel assembly. The core consists of these fuel assemblies, loaded in three different enrichment regions. New fuel is introduced into the outer region, and is moved inward in a preset pattern as determined by the reactor manufacturer.

The steam generators are vertical U-tube units containing Inconel tubes. Integral separating equipment reduces the moisture content of the steam at the turbine throttle to 0.25 percent or less.

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

The reactor coolant loop stop and bypass valves are motor operated gate valves, remotely controlled from the main control room and permit any loop to be isolated from the reactor vessel.

Nuclear auxiliary systems are provided to perform the following functions:

1. Accommodate reactor coolant system water requirements
2. Purify reactor coolant water

Criterion 4 - Sharing of Systems

Reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

Answer

Systems to be shared between BVPS-1 and BVPS-2 are provided in Section 1.7 of the Updated FSAR.

Criterion 5 - Records Requirements

Records of the design, fabrication, and construction of essential components of the station shall be maintained by the reactor operator or under its control throughout the life of the reactor.

Answer

BVPS-1 intends to maintain in its possession or under its control, a complete set of records of the design, fabrication, construction and testing of major Seismic Category I components throughout the life of BVPS-1. Section 12 of the Updated FSAR presents records requirements for: station operation, maintenance, and modification; and review of procedures.

1.3.2.2 Protection by Multiple Fission Product Barriers

Criterion 6 - Reactor Core Design

The reactor core shall be designed to function throughout its design lifetime, without exceeding acceptable fuel damage limits which have been stipulated and justified. The core design, together with reliable process and decay heat removal systems, shall provide for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and for transient situations which can be anticipated, including the effects of the loss of power to recirculation pumps, tripping out of a turbine-generator set, isolation of the reactor from its primary heat sink, and loss of all offsite power.

Answer

The reactor core with its related control and protection system is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater and loss of all offsite power.

The reactor control and protection instrumentation is designed to actuate a reactor trip for any anticipated combination of plant conditions when necessary to ensure a minimum Departure from Nucleate Boiling Ratio (DNBR) equal to or greater than the design limit and fuel center temperatures below the melting point of UO_2.

Section 3 discusses the design bases and design evaluation of reactor components. The details of the control and protection systems instrumentation design and logic are discussed in Section 7. This information supports the safety analysis presented in Section 14.

Criterion 7 - Suppression of Power Oscillations

The core design, together with reliable controls, shall ensure that power oscillations which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed.

Answer

Power oscillations of the fundamental mode are inherently eliminated by the negative Doppler and non-positive moderator temperature coefficient of reactivity.

Oscillations, due to xenon spatial effects, in the radial, diametral and azimuthal overtone modes are heavily damped due to the inherent design and due to the negative Doppler and non-positive moderator temperature coefficients of reactivity.

Oscillations, due to xenon spatial effects, in the axial first overtone mode may occur. Assurance that fuel design limits are not exceeded by xenon axial oscillations is provided as a result of reactor trip functions using the measured axial power imbalance as an input.

Oscillations, due to xenon spatial effects, in axial modes higher than the first overtone, are heavily damped due to the inherent design and due to the negative Doppler coefficient of reactivity.

The stability of the core against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distribution are discussed in Section 3. Details of the instrumentation design and logic are discussed in Section 7.

Criterion 8 - Overall Power Coefficient

The reactor shall be designed so that the overall power coefficient in the power operating range shall not be positive.

sufficient NPSH exists throughout their operating range. The original design of the recirculation spray subsystems for the BVPS-1 was similar to that for the Surry Power Station Units 1 and 2 and the North Anna Power Station Units 1 and 2. The conformance to Safety Guide 1 was discussed in the design of all these units by specific answers to AEC questions. The basis for achieving sufficient NPSH was presented to the NRC in Reference 1 and shown to be acceptable by issuance of Amendment No. 28 to Facility Operating License No. DPR-66 for BVPS-1.

1.3.3.2 Thermal Shock to Reactor Pressure Vessels (Safety Guide 2)

Compliance with Safety Guide 2 for Thermal Shock to Reactor Pressure Vessels is discussed in detail in Section 4 and the Technical Specifications.

1.3.3.4 Assumption Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors (Safety Guide 4)

The assumptions used to determine the radiological consequences of the DBA are in compliance with Safety Guide 4 with two exceptions:

1. It is assumed that 90 percent of the iodine inventory available for release from the containment is in elemental form and 10 percent in the form of organic iodine. The basis for this assumption is that subatmospheric containment in conjunction with the engineered safety features reduces the period of out-leakage from the containment to less than 60 minutes This short leak period minimizes the build-up of the inventory of organic and particulate forms of iodine during the period of interest after the accident.

2. The atmospheric diffusion model for ground level releases used in the analysis is more stringent than the model suggested in the Safety Guide 4 due to actual site meteorological and topographical data collected.

Accident meteorology is discussed in Section 2.2 and Appendix 2A and the offsite dose calculations for the DBA are discussed in Section 14.3.

1.3.3.6 Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems (Safety Guide 6)

Adequate redundancy and independence exists between standby (onsite) power sources and between their distribution systems in

accordance with the AEC regulatory position outlined in Safety Guide 6.

The electrical power loads for engineered safety features are separated into redundant load groups fed from separate buses such that loss of one group will not prevent operation of minimum safety functions.

The redundant power loads are each connected to buses which may have power fed from an offsite power source or an onsite power source (a diesel generator).

Four 125 v d-c systems, each complete with batteries, chargers, switchgear, and distribution equipment, are provided for engineered safety features equipment. These systems are not tied together.

A standby source of power for one redundant load cannot be automatically paralleled with the standby source of power for the other redundant load.

Each redundant 120 a-c engineered safety features load is supplied with power from a separate emergency diesel generator.

Figures 8.5-1 and 8.5-2 illustrate the physical arrangement of the emergency switchgear, 125 v d-c batteries, battery chargers, 125 v d-c distribution panels and 120 v a-c vital bus system equipment.

1.3.3.7 Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident (Safety Guide 7)

Table 14.3-9 lists the parameters used in calculating hydrogen sources. These parameters are identical to those given in Safety Guide 7. Further discussion of the post DBA hydrogen control system is presented in Section 6.5. An analysis of hydrogen generation and control is given in Section 14.3.4.4.

1.3.3.8 Personnel Selection and Training (Safety Guide 8)

The personnel of the BVPS-1 are selected and trained in conformance with the "Standard for Selection and Training of Personnel for Nuclear Power Plants," ANSI N18.1-1971[4] except for the operations manager as described in the technical specifications. Conformance with this standard assures that the requirements of the AEC Safety Guide 8 are met in their entirety.

The organization of BVPS-1 is described in Section 12.1. The training program for the various job classifications is listed in Section 12.2.

1.3.3.9 Selection of Diesel Generator Set Capacity for Standby Power Supplies (Safety Guide 9)

Each emergency generator set is rated as follows:

2,600 kW	8,760 hr/yr
2,850 kW	2,000 hr/yr
2,950 kW	168 hr/yr
3,050 kW	0.5 hr/yr

The basis for this rating is analyzed by emergency diesel generator steady state analysis. Each diesel generator is sized to ensure that the total loads of the engineered safety features required to be powered at any one time does not exceed 90 percent of the 0.5 hour per year rating.

Sequence starting of the motors associated with the safety features is provided to reduce the instantaneous load on the diesel generator. This ensures that adequate power is available to start and accelerate to rated speed all engineered safety features and emergency shutdown loads.

Each emergency diesel generator is up to speed and capable of accepting load within 10 seconds and energizes designated loads in a stepped sequence operation within an additional 60 seconds.

The speed and voltage variations of each emergency diesel generator are within the limits as set forth in Safety Guide 9.

During the preoperational test, the predicted engineered safeguard loads were verified by tests.

The selection of diesel generator capacity for standby power supply is in accordance with the intent of AEC Safety Guide 9.

1.3.3.10 Mechanical Cadweld Splices in Reinforcing Bars of Concrete Containments (Safety Guide 10)

Testing and sampling of mechanical splices in reinforcing bars used in the containment and other structures are in compliance with Safety Guide 10. Crew qualifications used differed from those required by Safety Guide 10. During the initial stages of construction, each member of the Cadweld crew was required to make one qualification splice for each 200 Cadwelds made. Later, this qualification requirement was increased to require two qualification splices, one in a vertical, and one in a horizontal position. Qualification requirements for Cadweld crew members, and testing and sampling the mechanical Cadweld splices in reinforcing bars are discussed in Section 5.2.5.3.

1.3.3.11 Instrument Line Penetrating Primary Reactor Containment (Safety Guide 11)

There are seven instrument sensing lines that penetrate the reactor containment as follows:

1. Four penetrations for the engineered safety features containment pressure

2. Two penetrations for the particulate and gas activity monitor

3. One penetration for the pressurizer dead weight calibrator.

The instrument sensing lines that are part of the protection system, Group 1 above, are redundant and independent and provide for testing of the protection system. These lines are provided with restriction orifices inside the containment to limit the inflow of air caused by an external failure of a line, valve body or instrument. This is in accordance with Safety Guide 11.

The sensing lines for Group 2 above are equipped with automatic containment isolation valves in accordance with Safety Guide 11.

The sensing line in Group 3 is discussed in Section 5.3.

1.3.3.12 Instrumentation for Earthquakes (Safety Guide 12)

Instrumentation for earthquake monitoring for BVPS-1 is provided in accordance with Safety Guide 12. This instrumentation is described in Section 5.2.8.1.

1.3.3.13 Fuel Storage Facility Design Basis (Safety Guide 13)

The fuel handling and storage facilities are designed to meet the following objectives:

1. Prevent loss of water from the fuel pool which could uncover spent fuel

2. Provide a safe, effective means of handling fuel, and protect it from mechanical damage

3. Provide a means of limiting any potential radioactive release to the environment in the event of a fuel handling accident.

The ferrite distribution in a weld will also vary depending on the weld position. This 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 ferrite will be the lowest in a given weld because of different weld or manipulations necessary to overcome effects of gravity.

In addition, Type 310 and 330 weld materials are always fully austenitic; yet sound welds are being made every day with these alloys using fine-tuned welding procedures. Also, welds are being made without the use of weld metal such as, electron beam welds and autogenous gas shielded tungsten arc welds.

Furthermore, the limits as set are arbitrary because various methods used to measure the percentage of delta ferrite yield widely differing results. The Welding Research Council has recognized this situation and has an organized approach that may result in an acceptable solution.

The basis for classifying the low, medium, and high energy input ranges is not given in the guide. Using our conservative welding procedure parameters, the following energy inputs are being applied everyday in producing high quality welds. They are (for American Welding Society designations):

1. SMAW 15.4 to 95 kJ/in. using 1/16 to 3/16 diameter electrodes

2. GTAW 2.16 to 32.5 kJ/in. using .03 to 1/8 diameter wires

3. GMAW 46 to 55 kJ/in. using .03 to 1/16 diameter wires

4. SAW 74 to 79 kJ/in. using .09 to 1/8 diameter wires

We have a large amount of evidence showing that the above energy input ranges produce fissure-free weldments in shop and on site welding.

Westinghouse PWR does not require in process delta ferrite determination. When the welding material is tested in accordance with the requirements of Section III, to the ASME Code (ASME-III) NB2430, and includes delta ferrite determination that sound welds displaying more than one percent average delta ferrite content by any agreed method of determination will be considered unquestionable. All other sound welds that display less than one percent average delta ferrite will be considered acceptable providing that there is no evidence of malpractice or deviation from procedure parameters. If evidence of the latter prevails, sampling will

be required to determine the acceptability of the welds. The sample size shall be 10 percent of the welds in the system or component. If any of these weld samples are defective, that is, fail to pass bend tests as prescribed by ASME Code, Section IX, all remaining welds shall be sampled and all defective welds shall be removed and replaced."

1.3.3.32 Use of IEEE STD-308-1971 "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations" (Safety Guide 32)

Class 1E electric systems, to the greatest extent possible, comply with Safety Guide 32.

Availability of offsite power is discussed in Appendix 1A.17.

The capacity of each battery charger supply is based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery to the fully charged state, irrespective of the status of the plant during which these demands occur.

1.3.3.33 Quality Assurance Program Requirements (Operation) (Safety Guide 33)

BVPS-1 has formed a Quality Assurance Department. This department is responsible for the administration of the operational quality assurance program.

The BVPS-1 Quality Assurance Manual has been revised to incorporate quality assurance for operations. This program complies with AEC Safety Guide 33. ANSI N45.2 and ANSI N18.7[9] (previously ANS 3.2) requirements are referenced within Safety Guide 33.

BVPS-1 Quality Control is responsible for the preparation of the quality control procedures necessary to comply with Safety Guide 33.

1.3.4 Guidelines Used for the Operations Quality Assurance Program

1.3.4.1 Regulatory Guides

REGULATORY GUIDE 1.33, NOVEMBER 3, 1972: QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATIONS)

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.33, November 3, 1972 [including referenced standards ANSI N45.2, 1971 and ANSI N18.7, 1972 (formerly ANS 3.2)].

Appendix A of Regulatory Guide 1.33, (Revision 2, February 1978), is used as guidance to ensure minimum procedural coverage for plant activities.

The biennial review of safety related plant procedures described in ANSI N18.7 will be replaced by programmatic controls related to procedure review found in plant administrative procedures, and a maximum six year procedure review period. Biennial audits of operating organizations will include a review of their procedures to provide additional assurance that existing programmatic controls are resulting in the timely revision of their procedures in response to operations experience deficiencies and procedure deficiencies identified by users.

REGULATORY GUIDE 1.37, MARCH 16, 1973: QUALITY ASSURANCE REQUIREMENTS FOR CLEANING OF FLUID SYSTEMS AND ASSOCIATED COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.37. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

REGULATORY GUIDE 1.38, MARCH 16, 1973: QUALITY ASSURANCE REQUIREMENTS FOR PACKAGING, SHIPPING, RECEIVING, STORAGE, AND HANDLING OF ITEMS FOR WATER-COOLED NUCLEAR POWER PLANTS

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.38. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

REGULATORY GUIDE 1.39, MARCH 16, 1973: HOUSEKEEPING REQUIREMENTS FOR WATER-COOLED NUCLEAR POWER PLANTS

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.39. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

REGULATORY GUIDE 1.54, JUNE, 1973: QUALITY ASSURANCE REQUIREMENTS FOR PROTECTIVE COATINGS APPLIED TO WATER-COOLED NUCLEAR POWER PLANTS

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.54. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

REGULATORY GUIDE 1.58, REVISION 1, SEPTEMBER, 1980: QUALIFICATION OF NUCLEAR POWER PLANT INSPECTION, EXAMINATION AND TESTING PERSONNEL

Qualification of inspection, examination, and testing personnel at Beaver Valley Power Station (BVPS) follows the guidance of this regulatory guide with the following clarifications:

ANSI N45.2.6, Paragraph 2.5:

ANSI N45.2.6-1978 recommends that organizations identify any special physical characteristics needed in the performance of each activity, and that personnel requiring these characteristics have them verified by examination at intervals not to exceed one year. At BVPS, examinations to verify personnel have the required physical characteristics will be scheduled on an annual basis with a maximum allowable extension of 90 days.

Regulatory Guide 1.58, Paragraph C.6:

The initial qualifications of individuals to Levels I, II, or III will generally be to the education and experience recommendations of ANSI N45.2.6-1978. However, in certain instances as determined by appropriate management, qualifications may alternatively be determined through test results and/or demonstration of capabilities. Individual requalification will meet or exceed the recommendation of the standard.

Paragraph 3.5.1 of ANSI N45.2.6-1978 lists recommended education and experience for qualification to Level I. BVPS will also accept a 4-year college degree plus 1 month of related experience or equivalent inspection, examination, or testing activities.

REGULATORY GUIDE 1.64: QUALITY ASSURANCE REQUIREMENTS FOR DESIGN OF NUCLEAR POWER PLANTS

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.64.

REGULATORY GUIDE 1.68, DRAFT 4, OCTOBER 2, 1973: PRE-OPERATIONAL AND INITIAL START-UP TEST PROGRAM FOR WATER-COOLED POWER REACTORS

The Operations Quality Assurance Program follows the guidance of Regulatory Guide 1.68.

REGULATORY GUIDE 1.70.11: INFORMATION FOR SAFETY ANALYSIS REPORTS QUALITY ASSURANCE SAFETY OPERATIONS PHASE

The Operations Quality Assurance Program requirements follow the guidance of Regulatory Guide 1.70.11.

REGULATORY GUIDE 1.88, OCTOBER, 1976: COLLECTION, STORAGE, AND MAINTENANCE OF NUCLEAR POWER PLANT QUALITY ASSURANCE RECORDS

The collection, storage and maintenance of quality assurance records at Beaver Valley Power Station will meet the intent of this regulatory guide with the following alternatives:

1. The design and construction of quality assurance record storage facilities will follow the guidance of ANSI/ASME NQA-1-1983, Supplement 17S-1, Section 4.4.

2. When temporary storage of records is required, the guidance of ASME NQA-1-1989, Supplement 17S-1, Section 4.4.3 will be followed.

REGULATORY GUIDE 1.144, SEPTEMBER 1980: AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS

Beaver Valley Power Station - Unit 1 (BVPS-1) will meet the intent of Regulatory Guide 1.144 for the auditing of its Quality Assurance Program during the operations phase with the following clarifications and alternatives:

Paragraph C.1

The applicability of the referenced regulatory guides/ANSI standards [RG 1.28: ANSI N45.2, RG 1.28: ANSI N45.2.9, and RG 1.74: ANSI N45.2.10] is as stated in the respective positions on these regulatory guides/ANSI standards as described in the UFSAR.

Paragraph C.3

Except for audit frequencies mandated by Title 10 of the Code of Federal Regulations, internal audits of selected aspects of operational phase activities shall be performed to ensure that audits described in Section 17.2 of the BVPS-2 UFSAR are completed within a period of 2 years (biennially).

The pre-audit and post-audit conferences required by Sections 4.3.1 and 4.3.3 of ANSI N45.2.12-1977 may be fulfilled by a variety of communications such as telephone conversations.

REGULATORY GUIDE 1.155, JUNE 1988: STATION BLACKOUT

The utilization of BVPS emergency diesel generators as alternate AC (AAC) power sources for coping with station blackout, and the reliability program for these generators follow the guidance of Regulatory Guide 1.155 (June 1988).[10,11]

REGULATORY GUIDE 1.163, SEPTEMBER 1995: PERFORMANCE-BASED CONTAINMENT LEAK TEST PROGRAM

The Containment Leakage Rate Testing Program is in accordance with the guidelines contained in Regulatory Guide 1.163. This regulatory guide provides guidance on an acceptable performance based leak test program, leakage rate test methods, procedures, and analyses that may be used to comply with the performance based Option B in Appendix J of 10 CFR 50. Refer to UFSAR Section 5.6 for additional discussion of containment leakage rate tests.

1.3.4.2 American National Standards Institute (ANSI) Standards

N45.2.5: DRAFT 3, REVISION 1, JANUARY 1974, "SUPPLEMENTARY QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS"

BVPS-1 follows the guidance of ANSI N45.2.5, Draft 3, Revision 1, January 1974. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

N45.2.8: DRAFT 3, REVISION 2, SEPTEMBER 1973, "SUPPLEMENTARY QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF MECHANICAL EQUIPMENT AND SYSTEMS FOR THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS"

BVPS-1 follows the guidance of ANSI N45.2.8, Draft 3, Revision 2, September 1973. Procedures and/or specifications were developed prior to, and implemented concurrent with the start of the operations phase.

N45.2.13: DRAFT 2, REVISION 4, APRIL 1974, "QUALITY ASSURANCE REQUIREMENTS FOR CONTROL OF PROCUREMENT OF ITEMS AND SERVICES FOR NUCLEAR POWER PLANTS"

The Operations Quality Assurance Program follows the guidance of ANSI N45.2.13, Draft 2, Revision 4, April 1974.

1.7 COMMON FACILITIES

The following identifies and discusses all structures, systems, subsystems and components of BVPS-1 that may be shared with BVPS-2. The discussion identifies those items that are essential in attaining and maintaining a safe shutdown as well as the considerations and protective measures taken to prevent essential systems from functionally being disabled by the failure of other essential and nonessential components. Each of the essential structures, systems and components are discussed in the appropriate Sections of the BVPS-1 and BVPS-2 Updated FSAR.

1.7.1 Identification of Shared Systems, Structures and Components

Structures, systems, subsystems and components and electrical systems to be shared between BVPS-1 and BVPS-2 that are considered nonessential because they are not required for attaining or maintaining a safe shutdown are provided in Tables 1.7-1, 1.7-2 and 1.7-3 respectively.

The sharing of emergency diesel generators between BVPS-1 and BVPS-2 during a station blackout event is discussed in Section 8.4.6.

Common structures, systems and components between BVPS-1 and BVPS-2 considered essential for attaining and maintaining a safe shutdown are discussed below.

Intake Structure

The Seismic Category I intake structure is a structure common to both BVPS-1 and BVPS-2. The BVPS-1 river water pumps and the BVPS-2 service water pumps housed in this structure, are considered essential systems and are so designed. Refer to Section 9.9 of the BVPS-1 Updated FSAR and Section 9.2 of the BVPS-2 Updated FSAR. Both the river water and service water systems are operated completely independent of each other and are designed to meet the single failure criterion. A cross-connect is provided between one of the two river water and one of the two service water discharge headers. This cross-connect is usually inoperable and is isolated from the two headers by two isolation valves. Catastrophic failure of one river water or service water pump can disable the other pump located in the same bay. However, since three 100 percent pumps are provided for the river water and the service water system and there is a cross-connect that can be used, there is no credible way that failure of one system can disable the other. The possibility of other essential and nonessential equipment failure damaging the essential river water and service water piping and pumps is discussed in Section 5.2.6 and the current high-energy pipe heat study and such a failure mode is not considered credible.

Control Room Emergency Pressurization System

The control room emergency pressurization system, discussed in Section 9.13, and shown in Figure 9.13-3, is used to pressurize the BVPS-1 and BVPS-2 main control area for one hour after a design basis accident to protect operating personnel from radioactive inleakage.

All air storage bottles and piping from the air storage tanks to the control room area are designed for seismic occurrences.

Control room pressurization air storage bottles are located in the Seismic Category I BR-TK-4A and BR-TK-4B coolant recovery tank cubicles.

Control room emergency pressurization tanks and piping inside the coolant recovery tank cubicles are sufficiently restrained to prevent jet force or pipe whip damage to the coolant recovery tanks.

The coolant recovery tanks contain water at atmospheric pressure. Hydrostatic forces developed from rupture of the tanks will not damage the air storage bottles or associated piping inside the cubicles.

Control room pressurization air compressor and system control equipment are located in the auxiliary building at El. 768 ft-7 inches. For a discussion of internally generated missiles and their effect on this system and other equipment in this area, refer to Section 5.2.6.

Main Control Area

The control areas for BVPS-1 and BVPS-2 are located in the same Seismic Category I missile-protected structure. However, the control boards for the individual units are physically and functionally separated within the main control area.

required to determine the metallurgical, chemical, physical, corrosion, etc., characteristics of the weldment. The additional tests that were conducted on a technical case basis are as follows:

1. Light and electron microscopy

2. Elevated temperature mechanical properties

3. Chemical check analysis

4. Fatigue tests

5. Intergranular corrosion tests using ASTM A-262 "Susceptibility to Intergranular Attack in Stainless Steels, Rec. Practices for Detecting", Practice E

6. Static and dynamic corrosion tests within reactor water chemistry limitations.

Post Weld Heat Treatment and Chemistry Control

The unstabilized austenitic stainless steel material specifications were used for the:

1. Reactor coolant pressure boundary

2. Systems required for reactor shutdown

3. Systems required for emergency core cooling are listed in Tables 1.8-1 and 1.8-2.

The unstabilized austenitic stainless steel material specifications used for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions, and for core structural load bearing members are listed in Table 1.8-3.

The water chemistry control is described in Section 4.2.8. These chemistry controls coupled with the satisfactory experience with components and internals using unstabilized austenitic steel materials which had been post weld heat treated, show compatibility of these heat treatments for stainless steel in a PWR chemistry environment.(2) Actual observation of post weld heat treated austenitic stainless steel after actual operation, indicate no effects of such treatments. Internals that were heat treated above 800°F and with subsequent service in the following plants have been examined and show acceptable material condition:

Robert Emmet Ginna

Jose Cabrera

Connecticut Yankee

San Onofre

Beznau, Unit 1

Yankee Rowe

Trino Vercellese (Vercelli)

For reactor vessel internals the austenitic stainless steel was given a stress relieving treatment above 800°F, using a high temperature stabilizing procedure. This was performed in the temperature range of 1,600°F to 1,900°F, with holding times sufficient to achieve chromium diffusion to the grain boundary regions to limit the effects of sensitization of Cr-carbide precipitation in the grain boundary. The stainless nozzles on the pressurizer were given a post weld treatment associated with fabrication of the head. No intergranular tests are planned because of satisfactory service experience as noted above.

1.8.2 Material Equivalency

Materials listed in the UFSAR that are qualified with an "or equivalent" statement may be replaced with an evaluated alternative material. Prior to the replacement of an existing material for a component part, an engineering technical evaluation is performed to determine suitability and acceptability for the application. These technical evaluations are performed utilizing approved procedures which meet the design control requirements of the BVPS Appendix B design control program. The site design control program under which acceptability of alternate materials is evaluated addresses many material properties and their interactions with the system environment. In a typical evaluation, material properties such as tensile strength, yield strength, ductility, fracture toughness, corrosion resistance, surface conditions, hardness, thermal conductivity, heat treatment, and electro-chemical potential are evaluated as appropriate for the application under evaluation. The term "equivalent," however, does not apply to materials specified in the UFSAR that are required by a legally binding commitment described in the license or NRC Safety Evaluation Report (SER).

1.8.3 Historical Information

UFSAR sections listed below have been determined to be historical based on Regulatory Guide 1.81 (References 1 and 2). This information is not intended or expected to be updated for the life of the plant.

While information provided in these sections has been designated as historical, associated design bases themselves should not. The original design bases continue to be part of the overall

design bases for the facility, and new information may warrant their update.

Section	Title
2	Site
11A	Estimated Radioactive Nuclide Concentrations in Waste Disposal Systems and in Discharge to the Environment
11B	Evaluation Of The Doses From Radiation Exposure Due To Normal Operation Of Unit 1 of the Beaver Valley Power Station
13	Initial Tests And Operation
14A	Report Covering The Effects Of A High Pressure Turbine Rotor Fracture And Low Pressure Turbine Disc Fractures At Design Overspeed
14E	Generic Sensitivity Study Results For A 3-Loop Plant With 17 x 17 Fuel
A.1	Quality Assurance Program (Note: The Operations Phase Quality Assurance Program is described in Unit 1 UFSAR Table A.1-1 and Unit 2 UFSAR Section 17.2)
A.2	Duquesne Light Company Design and Construction Quality Assurance Program
A.3	Stone & Webster Engineering Corporation Quality Assurance Program (Design and Construction Phase)
A.4	Westinghouse Pressurized Water Reactor Systems Division Quality Assurance Plan (Design and Construction Phase)
A.5	Westinghouse Nuclear Fuel Division Reliability and Quality Assurance Program

References for Section 1.8

1. "ASTM Recommended Practice for Detecting Susceptibility to Intergranular Attack in Stainless Steels," ASTM A-262, The American Society for Testing Materials.

2. W. S. Hazelton, "Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems," WCAP-7735, Westinghouse Electric Corporation (August 1971).

3. "Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)," Nuclear Regulatory Commission Regulatory Guide 1.81 (September 1999).

4. "Guidelines for Updating Final Safety Analysis Reports," Nuclear Energy Institute guidance document NEI 98-03 (Revision 1, June 1999).

Design Conformance

Many components of the river water system and the component cooling system are regularly in service during normal operation and, therefore, provide assurance of the availability and performance of the equipment and system.

The design of the river water components and system allows, to the extent practicable, the periodic testing of the operability of the system as required for operation in the loss-of-coolant accident and/or loss-of-unit power.

References

1. Section 9.8, Primary Component Cooling System
2. Section 9.9, River Water System
3. Section 10.3.9, Turbine Plant Cooling Water

1A.50 CONTAINMENT DESIGN BASIS (CRITERION 50)

Criterion

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Design Conformance

The containment structure is designed to leak at a rate which is less than 0.1 percent of the containment volume per day under post DBA conditions. The containment is designed to withstand loads above those that are conservatively calculated to result from a DBA (Sections 14.2.5.1 and 14.3.4) by a margin as discussed below. The containment has a design margin of about two percent over the maximum calculated peak pressure. The two percent is based on very conservative limiting assumptions.

1A.51 FRACTURE PREVENTION OF CONTAINMENT PRESSURE BOUNDARY (CRITERION 51)

Criterion

The reactor containment boundary shall be designed with sufficient margin to ensure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

Design Conformance

Ferritic materials for the reactor containment boundary are specified so that the nil ductility transition (NDT) temperature of the steel is at least 60°F below the lowest of the minimum operating, maintenance, containment building testing or postulated accident temperatures.

An applicable technical reference for this subject is provided in Reference 3. Figure 23 of Reference 3 shows the Fracture Analysis Diagram (FAD), which plots stress (as percent of yield strength) vs. the temperature in excess of the NDT temperature. The liner is designed so that no stress exceeds the crack arrest temperature (CAT) curve, as shown in the FAD. This is a very conservative approach, which ensures that flaws of any size will not be propagated to a rapid (i.e., brittle) fracture.

Uncertainties of determining the NDT temperature are minimized by using the Drop Weight Test DWT, per ASTM E-239[4] (previously ASTM E-208) for material five-eighths inch or thicker. The DWT is widely recognized to determine the true material NDT temperature. Plates thinner than five-eighths inch are impact tested by full or subsized Charpy V or by Drop Weight Tear Test methods. Also, the weld procedure qualification will demonstrate that the NDT temperature of the weld metal and heat affected zones follow the same criteria as for the base metal.

1A.52 CAPABILITY FOR CONTAINMENT LEAKAGE RATE TESTING (CRITERION 52)

Criterion

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Design Conformance

The containment structure and related equipment which will be subjected to the containment test conditions, as described in Section 5.6, will be designed so that the periodic integrated leakage rate testing can be conducted at calculated peak containment pressure as per Appendix J to 10CFR50, "Reactor Containment Leakage Testing for Water Cooled Power Reactors."

1A.53 PROVISIONS FOR CONTAINMENT TESTING AND INSPECTION (CRITERION 53)

Criterion

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

Design Conformance

The design of the reactor containment provides for access to all important areas for periodic inspection. The design includes the placement of leak test channels over most liner seam welds, which are inaccessible after construction, and penetration-liner welds. These channels are not considered as safety related, however, they may be pressurized to containment design pressure to permit inspecting and testing the leaktightness of the covered areas. The operation of the containment provides for a continuous surveillance program of the leaktightness of the containment. The leakage monitoring system is described in Section 5.4.2.

1A.54 PIPING SYSTEMS PENETRATING CONTAINMENT (CRITERION 54)

Criterion

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Design Conformance

Piping systems penetrating the reactor containment do so in accordance with the design bases set forth for the containment isolation system (Section 5.3.2). This ensures redundancy, reliability and performance capabilities reflecting the importance to safety of isolating the piping systems. Special

test connections are provided where required to ensure the capability to determine if individual isolation valve leakage is within acceptable limits. The containment leakage monitoring system (Section 5.4.2.2) also provides the capability of detecting unacceptable containment leakage.

1A.55 REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT (CRITERION 55)

Criterion

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provides for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provided greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Design Conformance

The containment isolation arrangements for all lines that are part of the reactor coolant pressure boundary, and that penetrate

of 107 inches of water above a withdrawn fuel assembly at its highest point of travel. Under these conditions, the dose rate is less than 50 mrem per hour at the water surface.

The spent fuel handling system is designed to preclude gross mechanical failures which could lead to significant radioactivity releases. Floor and trench drain systems provide backup by collecting leakage which might occur. Design of the fuel storage pool ensures that there is no significant loss of fuel storage coolant under accident conditions. Decay heat from spent fuel is dissipated in the water of the storage pool and subsequently removed by a cooling system. If an accident were to damage the fuel pool cooling system, the heat of the spent fuel would have to be removed by evaporation of the spent fuel water. Make-up water can be supplied from the engine driven fire pump. Redundancy of the fuel pool cooling system components is provided to ensure reliability in maintaining the storage pool water cleanliness, level and heat removal ability. The fuel pool cooling and purification systems are described in detail in Section 9.5.

Radioactive gases, which may leak from spent fuel or radioactive waste disposal tanks in the decontamination and auxiliary building, are collected by the fuel building system. All discharges from these systems are monitored. All monitoring systems are discussed in Section 11.3.

Periodic surveys by Radiation Control personnel using portable radiation detectors ensure that radiation levels outside the shield walls meet design specifications. Section 11.3 describes shielding requirements.

The possibility of a fuel handling incident is very remote because of the many administrative controls and physical limitations imposed on fuel handling operations. For a description of the worst possible accident hypothesized refer to Section 14.

1A.62 PREVENTION OF CRITICALITY IN FUEL STORAGE AND HANDLING (CRITERION 62)

Criterion

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Design Conformance

The spent fuel storage racks are divided into two physical regions, Region 1 and Region 2. A third administratively controlled region, Region 3, is part of Region 2. Each region is

defined by fuel enrichment vs. burnup limitations. The racks, free standing on the floor of the spent fuel pool, are sized to hold 1622 spent fuel assemblies (additionally there are 2 failed fuel assembly cannisters). The spent fuel assemblies are placed in vertical cells within the rack, continuously grouped in parallel in both directions. Cell pitch is approximately 10.8" for Region 1 and approximately 9" for Region 2. In addition, Boral panels are installed in the walls of the individual cells to maintain subcriticality. The racks are so arranged that the spacing between fuel elements cannot be less than that prescribed. Borated water (approximately 2000 ppm) is used in the spent fuel pool. Even if unborated water were introduced, the spacing and Boral maintain subcriticality with $K_{eff} \leq 0.95$ for stored fuel.

The new fuel assemblies are stored dry in a steel and concrete structure within the fuel building. The assemblies are stored vertically in racks in parallel rows, having a fuel assembly center-to-center distance of about 21 inches. There is storage space for one-third (53 assemblies) of a core plus 17 spare assembly spaces. The steel rack construction prevents possible criticality by requiring that the spacing between fuel elements will not be less than that prescribed. In the event of accidental flooding of the fresh fuel racks, the center to center spacing of the fuel assemblies results in $K_{eff} \leq 0.95$ under full water density conditions and $K_{eff} \leq 0.98$ under low water density (optimum moderation) and aqueous foam conditions. Criticality prevention is discussed in detail in Section 9.12 and Section 3.3.2.7.

During handling, as a result of the hypothetical worst case accident the safeguards are designed such that the consequences of this accident meet 10CFR100 guidelines. For a complete description of this worst case accident, refer to Section 14.2.

1A.63 MONITORING FUEL AND WASTE STORAGE (CRITERION 63)

Criterion

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

Design Conformance

Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. The fuel pool water temperature is continuously monitored. The temperature is displayed in the main control room where an audible alarm will sound should the water temperature increase

SECTION 2

SITE

LIST OF EFFECTIVE PAGES

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2i	through 2vi	Revision 18	January, 2000
2-1		Revision 12	January, 1994
2-2	and 2-3	Revision 14	January, 1996
2-4		Revision 15	January, 1997
2-5		Revision 13	January, 1995
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SECTION 2

SITE

2.1 DESCRIPTION AND DEMOGRAPHY

2.1.1 Location and Description[1]

The Beaver Valley Power Station Unit No. 1 (BVPS-1) is located in Shippingport Borough, Beaver County, Pennsylvania, on the south bank of the Ohio River. The site is approximately one mile from Midland, Pennsylvania, five miles from East Liverpool, Ohio, and approximately 25 miles from Pittsburgh, Pennsylvania. The coordinates are 40°37' 18" north and 80°26' 2" west. The Universal Transverse Mercator coordinates are 547,900 meters east and 4,496,680 meters north. Figure 2.1-1 shows the general site location out to a radius of 200 miles.

The site comprises approximately 453 acres including 26 acres of right of way. Also on the site and immediately to the west of the reactor location is the former site of Shippingport Atomic Power Station (SAPS) which was managed by Duquesne Light Company for the Department of Energy (DOE). The SAPS terminated operations October 1, 1982, and was dismantled by the USDOE. Immediately to the east of the BVPS-1 reactor location, and also onsite is the Beaver Valley Power Station Unit 2 (BVPS-2). Figure 2.1-2 is an aerial photograph of the Beaver Valley Power Station site. Local site topography, site boundary and exclusion radii are shown in Figure 2.1-3.

The Pennsylvania Department of Transportation has a right-of-way across the easterly end of the property on which is constructed a portion of Route 168 including the southerly approach to the Shippingport Bridge.

The site area and adjacent Ohio River provide a minimum exclusion radius of 2,000 ft. The property boundaries also define the nearest approach to the reactor upon which the Offsite Dose Calculation Manual limits on gaseous effluents are based. Gaseous releases will occur at the BVPS-1 primary auxiliary building, containment building, and at the BVPS-1 cooling tower. The shortest distance to the site boundary from the containment building is 2,000 ft to the northeast and from the cooling tower is 1,380 ft to the east-northeast. The nearest occupied residence is approximately 2,100 ft from the reactor location.

Phillis Island lies approximately 400 ft off the shoreline of the site. The previous owner of the island, Dravo Corporation, agreed in 1955 not to use or permit the use of the land for any structure, place or area where the public at large can assemble. This agreement was binding on Dravo Corporation and any future purchaser or lessee until March, 1994. A new agreement,

extending the expiration date to 2010 and further delineating the uses which can be made of the island, has been negotiated. Phillis Island was sold to the United States of America in 1990 and through the purchase agreement is bound by the uses which can be made of the island as described in the previous agreement.

The Freeport Development Corporation purchased approximately 46 acres from DLC in 1995. This land, located along the southern site boundary, includes 7.4 acres which are within the 2000-foot exclusion area boundary. A legal agreement binding on Freeport Development Corporation as on any future purchaser or lessee delineates and restricts the uses which can be made of the land.

The site boundary is shown in Figure 2.1-3. Within the site boundary are restricted areas which are areas to which access is limited for the purpose of controlling exposure to radiation and radioactive material. A description of restricted area locations can be found in the Health Physics Manual.

Periodic monitoring of external dose rate levels and environmental sampling in the area adjacent to the river's edge and around the perimeter of the restricted area are included as part of the surveillance program (see Section 2.8).

Gaseous releases from BVPS-1 will occur at the containment building, cooling tower, and auxiliary building.

With the exception of the northeast corner of the site, near the center of which the station is located, the site area is very hilly. It rises from the river, which has a normal pool El. 664.5 ft above mean sea level (MSL), to a maximum El. 1160 ft above MSL. Prior to grading, the station location consisted primarily of three terraces: a high level terrace at El. 735 ft on which the reactor containment is located, an intermediate terrace at approximately El. 690 ft, and a low level terrace at El. 675 ft. Site filling has been done to provide a bench at El. 707 ft riverward of the station on which the transformers are placed. Site drainage is primarily to the river, but with some drainage in the northeast portion of the site to Peggs Run, a small stream which enters the river at a point just west of Route 168.

2.1.2 Population

The distance and direction to population centers that have more than approximately 20,000 inhabitants and are located within 50 miles of the site are listed in Table 2.1-1. The nearest such population center is East Liverpool, Ohio, with a population in 1970 of 20,020. The population of East Liverpool, and the majority of the other population centers in this area, decreased between the 1960 census and 1970 census primarily because the lack of industrial diversification resulted in a decrease in employment opportunities as the number of employees required in the basic iron and steel industry declined. This decreasing trend is expected to level off in the near future and then employment is projected to gradually increase as more emphasis is

miles of the site are schools. The effect of the public facilities on population distribution is negligible. These facilities are utilized by the local population. The effect of these facilities, such as schools, is to temporarily concentrate the distributed population. Parks near the site are listed in Table 2.1-3. The largest park is Raccoon State Park, eight miles south of BVPS-1. In 1970, total attendance at the park was 480,000 people.[9]

2.1.3 Land and Water Use

BVPS-1 is situated in an area characterized by the sharp contrast in land use between the river valley area transversing the region, and the inland countryside. The Ohio River Valley can be described as being a highly industrialized area in comparison to the inland areas which can be best described as being rural in character.

2.1.3.1 Industry

The general area in which BVPS-1 is located is part of the large Pittsburgh industrial complex, which is centered about the City of Pittsburgh. The combination of available raw materials, product markets and transportation facilities led to the development of the region as a major industrial center with the manufacturing of iron and steel being the most important factor in the region's economy. The heavy industries have settled, for the most part, on the flat shelves of land adjacent to the rivers. The steep slopes of the river valley have, for the most part, contained industry close to the banks of the river. This led to the development of the river mill town. The railroads also located next to the river and the commercial and residential areas, restricted by the topography of the river valley, stretched out in a linear pattern along the river.

In Beaver County, 67 percent of the total industrial labor force is employed in the primary metals group - blast furnaces, steelworks and rolling mills. The second largest industry, with 11 percent of the labor force, is the fabricated metal products group, especially fabricated structural steel. The electrical equipment industry employs eight percent of the labor force, while the stone, clay, glass, and concrete industries employ four percent. The other major industrial activity is the chemical group which employ three percent of the labor force.

The industrial giant in the region, and by far the largest employer with close to 12,000 employees, is the Jones & Laughlin Steel Corporation in Aliquippa, about ten miles east of the Beaver Valley site. The world's largest electrically controlled railroad classification yard is located at Conway, across the river from Monaca. The Shippingport Atomic Power Station (now decommissioned), operated by the Duquesne Light Company, adjacent to the Beaver Valley Power Station, was the United States' first commercial nuclear power station. The nearest industrial activity to the site is the steel mill complex located in

Midland, between one and two miles northwest of the site, where over 6,000 persons are employed. There is one industrial operation located in Shippingport Borough. It is a coal mining company, employing 60 people, which operates a deep mine and coal washing facilities located about one mile southwest of the entrance of the site.

The urban complex of East Liverpool, Ohio, including Chester and Newell, West Virginia, begins about five miles west of the site and stretches for several miles down the Ohio River. The East Liverpool area industrial base is dependent on pottery and steel for most of its employment. At one time, East Liverpool was known as the pottery center of the world, but foreign competition and the use of plastic materials for tableware has resulted in a decline in the pottery industry.

Table 2.1-4 lists the major employers in the area surrounding the site, while Table 2.1-5 shows statistical data for manufacturing industries in Beaver County.

Mineral resources including coal, clay, gas, oil, sand, and gravel are found in the region surrounding the site. Bituminous coal is the most important mineral being extracted and coal reserves are considered to be extensive. However, relatively few workers are engaged in mining operations and the employment forecast is for a decline in mining employment as the use of automated mining techniques increases. In Beaver County, deep mining is the predominant method for getting the coal out of the ground, although extensive areas of strip mining are found within the region especially in northern Beaver County and in northern Washington County.

The total number of persons employed in southwestern Pennsylvania is projected to increase 42 percent by the year 2000 according to a study prepared by the Southwestern Pennsylvania Regional Planning Commission (SPRPC). However, not all industry groups will experience this growth. Historically, the southwestern Pennsylvania region has been a heavy industry center dominated by the manufacture of iron and steel. The employment forecast for the region, shown in Table 2.1-6 indicates that in the manufacturing category employment gains in fabricated metals, machinery and transportation equipment will be offset by declines in basic steel production and in the stone, clay, and glass industries. The net result will be a stabilization or even a slight decrease in the number of persons employed in manufacturing production jobs. Employment statistics for the southwestern Pennsylvania region show that this trend has been in effect for the past several years. Factors contributing to this trend have been the increased use of automation, foreign competition, dispersion of markets and the development of steel making capacity in other areas of the country. While employment has decreased in the basic steel industry, the productivity per worker has increased as well as wages and salaries and the value of production.

Employment in the non-manufacturing jobs is projected to grow by almost 70 percent in the next three decades. As shown in Table 2.1-6, the largest growth will occur in services and government.

Storage tank facilities for gasoline and oil are mostly located along the river. The closest oil tanks are in Midland, Pa. directly across the river from the site.

Industrial plants near the site store relatively small quantities of toxic gases such as chlorine. The Midland Water Treatment Plant utilizes chlorine. Chlorine is stored on site in eight 1-ton containers outside of the BVPS-1 turbine building. No significant quantities of propane or LPG are stored within five miles of the site.

Up to 1 ton of explosives may be stored by the Peggs Run Coal Company. This supply is replenished about every three weeks. The coal mine is an active project. Dynamite is shipped by a 3/4 ton pickup truck or a small van from the Austin Powder Company in Evans City, Pa., via Route 168. The Peggs Run Coal Company is about one mile southwest of the site and is shielded by the large hill to the south of the site.

2.1.3.2 Transportation

The region is served by five transportation systems: waterways, railroads, highways, air and pipelines.

The first major transportation system was the rivers. The early economic growth and pattern of development of the region was inextricably tied to the rivers. After 1860, the rivers gradually diminished in importance as a transportation system and the railroads became the primary carriers of industrial materials. However, advances in technology such as, first, steam, and then, diesel power plus a program of building locks and dams to improve navigation led to a revival in river traffic. In 1910 the volume of goods hauled on the rivers was only 7 percent of the combined river and railroad traffic but by 1969 had risen to close to 40 percent. In 1960 the tonnage of freight handled on the upper Ohio River was 22 million tons. By 1969 the tonnage had risen to 33 million tons. The locks at Montgomery Dam, located three miles upriver from the site, recorded 6,574 commercial lockages for 1970. The commodities shipped on the waterways include coal, coke, petroleum, sand and gravel, steel products and chemicals. A map showing the normal river channel used for barge traffic is shown on the U.S. Army Engineer District Charts, Figures 2.1-8 through 2.1-11.

The bulk of industrial materials are transported by the railroads. The placement of the rail lines was governed by the topography. Because the railroads needed level and continuous corridors, they followed essentially the same courses as the rivers and streams. One of the first rail lines in the region

ran from Pittsburgh up the eastern bank of the Beaver River to the Great Lakes region. That line is one of the main Penn Central lines. The world's largest electrically controlled railroad switching yards, capable of handling 10,000 cars per day, is located on this line at Conway about ten miles east of the site. Another heavily traveled Penn Central line follows the north bank of the Ohio across the river from the station site. There is also a Penn Central right-of-way on the site. This line is of minor importance since the line is controlled by the licensee and its use is limited to the servicing of the Beaver Valley Power Station. The railroad west of the site has been abandoned by the Penn Central Railroad. There are no through shipments. The railroad siding is leased by the licensee and serves only the site. The railroad on the north side of the Ohio River is approximately 1,200 ft from the site.

The type of quantity of toxic gases that may be transported within one mile of the plant site was not determined at the time of the pre-operational phase investigation because of data availability limitations. Sources consulted in an attempt to secure this information include:

1. U.S. Environmental Protection Agency - Boston Office
2. U.S. Environmental Protection Agency - Philadelphia Office
3. Interstate Commerce Commission - Philadelphia Office
4. Interstate Commerce Commission - Washington, D.C. Office
5. U.S. Department of Transportation, Office of Hazardous Materials
6. U.S. Department of Transportation, Harrisburg, Pa. - Motor Transportation Dept.
7. U.S. Coast Guard - Louisiana
8. Union Barge Lines - Pittsburgh, Pa.

All nongovernment information available prior to the operations phase is included in the Attachment to Section 2.1.

In the event of transportation accident involving toxic gas, the control room may be pressurized to exclude hostile environments. Emergency air breathing apparatus is also available to control room occupants. These precautions will help minimize the effects of the accident.

State Highway 68 provides the main access from the residential areas east of the site to the industrial complexes along the

2.1.7.9 Potential Cooling Tower Collapse

The mode of failure of the cooling tower is expected to be inward during a postulated collapse. It is expected that no missiles with greater kinetic energy than the design basis missile could reach safety-related structures or equipment. The only known collapse due to wind loading has been inward. Missiles generated by a tornado are expected only to penetrate the cooling tower locally without causing failure. The design basis missiles impacting on the cooling tower could not generate a missile with greater kinetic energy.

2.1.7.10 Bruce Mansfield Power Station - Slurry Discharge Pipeline

The Slurry Discharge Pipeline (see Figure 2.3-25) is intended to transport sludge, in the form of a water slurry, from the Sulphur Dioxide Scrubbers at Bruce Mansfield Power Station to the Little Blue Run Disposal Area. The Disposal Area is located approximately five miles down river from the BVPS-1.

The system characteristics of the pipeline are:

1. PIPELINE ROUTING: The pipeline will circumnavigate BVPS-1. The routing was purposely chosen to preclude any possible damage to safety-related structures or equipment in the event of a leak. The closest point of approach to any safety-related structure is approximately 1200 ft. The entire length of pipeline will be laid below grade, and a minimum earth cover of 30 inches will be provided.

2. PUMPING STATION: The pumping station is located at Bruce Mansfield Power Station. The pumping station is continuously manned and is equipped with audible and visual indicators as well as recording equipment to provide continuous control of pumping operations. The operator has visual indication of system valve position, which lines are in use and which pumps are running, as well as pump discharge pressure and temperature. Magnetic flow meters compare total flow at the discharge of the pumping station to the flow at the discharge to the impoundment area and provide visual and audible alarms at the pumping station should a significant mismatch occur. This allows the operator to identify a ruptured pipeline and switch flow to the standby pipeline. The entire pipeline is visually inspected by daily roving patrols. The roving patrol is radio equipped to ensure rapid transfer of information should damage or leakage be discovered.

3. PIPELINE: The pipeline will consist of four pipes, two 12 inch and two 8 inch and four pumps. Each pump has a discharge relief valve, and discharges to a valved manifold which allows various pump combinations to be utilized. The pipeline is constructed of ASTM-A106-B steel pipe and has a design pressure of 1310 psig. System pressure will vary between 600 psi and 1100 psi for flow rates of 400 to 3600 gpm. Wear is estimated to be 0.008 inch per year. The expected life of the pipe sections is 30-35 years. Manual isolation valves are installed in each of the four pipelines on the east and west sides of the site property as well as between BVPS-1 and the discharge impoundment.

4. SLURRY: The slurry is non-toxic, non-flammable and essentially non-corrosive. Its composition will vary somewhat, depending on power plant operation. Normally, the slurry will be 32.3 percent solids by weight and the composition of the solids will be approximately:

   a. fly ash, 30 percent

   b. inerts, 3 percent

   c. limp grits, 1.2 percent

   d. CALCILOX, 9.7 percent

   e. calcium carbonate, 0.6 percent

   f. calcium sulphate, 20.6 percent

   g. calcium sulphite, 32.6 percent

   h. unreacted lime, 0.6 percent

   i. magnesium hydroxide, 1.3 percent

   j. calcium hydroxide, 0.8 percent

The sludge is treated with 1.0 percent lime to increase the pH to 11.0. CALCILOX is added as a solidification aid.

In summary, this pipeline is not considered to be a safety hazard to the plant due to:

1. The routing of the pipeline which was purposely laid out to circumvent the plant structures

2. The leakage detection measures employed in the design

3. Installed capability to isolate any leaking or ruptured slurry line.

15. USNRC NUREG/CR-2858, "PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations", Pacific Northwest Laboratory (November 1982).

16. Calculation ERS-SFL-83-015 r0, Accident Analysis X/Q Values (1983).

17. Halliburton NUS Environmental Corporation, Control Room X/Q Values for the Beaver Valley Power Station (1991).

18. J. V. Ramsdell, Atmospheric Diffusion for Control Room Habitability Assessments, NUREG/CR-5055 (1988).

19. Calculation ERS-SFL-96-021 r0, RG 1.145 Short Term Accident X/Q Values for EAB and LPZ, Unit 1 and Unit 2, based on 1986-1995 Observations (1996).

also mark the local groundwater basin divides. Groundwater levels under the upland surface lie at depths of 10 to 50 ft below surface, averaging 30 ft. The phreatic surface has a gradient of 50 percent on steep hillsides, 25-30 percent on gentler hillsides, and 15 percent or less along tributary streams. In all areas, the groundwater flows downslope and eventually enters the terrace upstream of the plant site or enters the river, downstream of the site. Groundwater migration in the bedrock appears to be constant and slow. Because of the low permeability of the rocks, recharge from rock to the terrace gravels is negligible. There are no known aquifers in the bedrock under the site.

2.3.2.1.2 Site Condition

The station is located on a system of terraces along the south side of the river. The terrace on which the station is located is about 4,000 ft long and 1,800 ft wide at its widest point. Downstream of the station, the terrace pinches out against the steep bedrock valley wall. To the northeast, it is limited by a buried bedrock spur which extends northwesterly almost to the river's edge at a point about 2,500 ft upstream of the station.

The soils of the terrace are predominantly sands and gravels except for the younger deposits near the river. The permeable gravels crop out in the river. Groundwater under the terrace is interconnected with the river. Observations during construction showed that groundwater level elevations are very close to river level at normal pool and respond very quickly with changes in river level as the river rises in flood.

Recharge to the groundwaters of the terrace in the site area is primarily from precipitation on the immediate area. Assuming an infiltration of about 35 percent which would be expected for these soils, topography, and climatic conditions, this would amount to an average infiltration of about 12 inches of water per year which is about 900 gallons per day per acre. Additional recharge occurs during periods of rising river level as the groundwater rises. This again is discharged as the river falls. Under normal river conditions, the groundwater levels under the terrace on which the station is located slope very gently towards the northwest as shown by the groundwater contours on Figure 2.3-3.

2.3.2.2 Usage

Two wells, in the terrace gravels, were drilled to supply cooling water (and augment water supplies) to the Shippingport Atomic Power Station (now decommissioned). They are located relatively close to the river as shown on Figure 2.3-3. A temporary well was drilled to provide water for sanitary uses and construction uses during the construction of the BVPS-1. Production is less than 50 gpm. This will be retained in service for similar purposes for BVPS-2. An additional temporary well will be

installed about 1,000 ft upstream of the station to supply water to a concrete mixing plant during construction of BVPS-2. There are no municipal groundwater supplies located in this terrace. Two wells were drilled for the Bruce Mansfield Fossil Fuel Power Plant about 6,000 ft upstream of the station at the location shown on Figure 2.3-3. These wells are close to the river. As indicated, they are upstream of the buried bedrock nose. Consequently, they are effectively isolated from the groundwaters under the station and probably will be recharged largely by infiltration from the river.

There are approximately 48 domestic wells located upstream of the station as shown in Figure 2.3-3. All but three of these are located on or upstream of the buried bedrock nose and are thus isolated from the groundwaters under the station. The nearest domestic well is approximately 2,300 ft upstream of the plant. Groundwater level in this well was found at El. 681 ft, 15 ft above groundwater level in the station area at the time of observation.

Bedrock wells in the upland area all serve domestic purposes. Yield of all of these is very low and all terminate at elevations well above yard elevation at the station site.

There are no known plans for other future developments upstream of the station. Accordingly, maintenance of existing groundwater gradient is anticipated.

The hydraulic gradient in the terrace gravels along a northwest-southeast line along the cooling tower centerline varies from 8.6 percent near the toe of the bedrock scarp to about 0.1 to 0.2 percent in the power station and cooling tower foundation area. The coefficient of permeability is 0.2 to 0.46 ft per minute based on pumping tests from two wells developed for the Shippingport Atomic Power Station. For these gradients and coefficients of permeability, the velocity towards the river would be about 0.3 to 1.5 ft per day at the station.

Groundwater incursion, caused by excessive pumping on site, would not affect any domestic or industrial supplies because they all lie upstream and upgradient of the station site. Use of groundwater on the site is not expected to deplete regional or local supplies because of the alluvium which is part of the Ohio River groundwater regimen, which recharges the system.

2.3.2.3 Accidental Effects

As previously discussed, all groundwater passing under the power station site moves into the Ohio River, which acts as a natural barrier to the migration of groundwater contaminants. Groundwater migration is effectively blocked to the southwest where the alluvium pinches out against a bedrock cut scarp

covered by relatively impervious colluvium just above river grade. The station is so designed that accidental spills of radio nuclides would be contained within buildings. Even if it were postulated that a spill to ground could occur, the volume of water and low flow rates in the alluvium below the plant site indicate that should liquid waste enter the groundwater, it would be diluted and slowly transported into the river. The time required to reach the river after a pollutant spill at the reactor probably would be between 620 days and 3,000 days, based on a range of gradients of 0.1 to 0.2 ft per 100 ft and a permeability coefficient range of 0.2 to 0.46 ft per minute. This migration rate of 1.7 to 8.2 years assumes steady conditions and an unchanged phreatic surface. Actually, one or more floods could be expected in this period; however, since the alluvium below the site is part of the Ohio River regimen, rising groundwater levels would correspond to rising river level. Therefore, the flood waters would tend to dilute any spilled pollutants and the diluted materials would then be discharged into the river as the river level fell.

Migration of contaminants upstream to domestic water supplies could not occur since such wells are upgradient from the station area.

2.3.2.4 Monitoring

The design of the station is such that all potential sources of spills of radioactive materials are contained within the buildings. Accordingly, there is no hazard of a spill to groundwater. Under these circumstances, monitoring of groundwater to protect users is not considered necessary and will not be provided.

2.3.3 Floods and Dam Failure Upstream

The station has the ability to achieve a safe shutdown condition, through the use of design features and procedural controls, before the maximum level of the Ohio River Probable Maximum Flood occurs. All Category I structures are designed for the buoyancy and hydrostatic pressures associated with this flood level. These flood conditions are discussed in the report dated January, 1970 from the Corps of Engineers. The Corps of Engineers concludes that the most critical conditions believed possible would result from the Probable Maximum Flood (PMF).

The development of the PMF is not detailed here. A general outline of its development is given in Attachment "A" to Section 2.3. Information pertaining to further details of river hydrology may be obtainable from the U.S. Army Corps of Engineers, Pittsburgh District Office.

Coincident wind wave activity is not discussed since the PMF developed by the Corps is considered by them to be a one in a

geologic era event and, as such, is extremely conservative without wave activity.

Potential dam failures are also discussed in general terms in Attachment "A" to Section 2.3. Further details may be obtainable from the Corps.

Ice is not believed to be of concern here because lock and dam control systems have opened this part of the river to heavy amounts of ship and barge traffic year round.

The Corps of Engineers initially set a level of 707.2 ft for the Standard Project Flood. This level was used for initial station design. Subsequently, the analysis by the Corps of Engineers in 1970 revised the Standard Project Flood level downward to 705 ft. No portion of the station has been redesigned just to take advantage of this reduced level. However, portions of the station designed after the latter date, or which required a redesign for other reasons after that date, are designed for a Standard Project Flood of 705 ft. The emergency diesel generators are located at El. 735.5 ft. The containment is waterproofed generally to El. 730.0 ft, and is unaffected by the Probable Maximum Flood. The basement of the service building is at El. 713.5 ft; however, the structure is waterproofed and reinforced so that it is unaffected by floods to El. 730.0 ft. The duration of the Probable Maximum Flood above El. 728.0 ft is about 18 hr, which is insufficient time for soil permeability to provide hydraulic uplift above El. 728.0 ft. The service building is therefore designed for an uplift equivalent to a flood reaching El. 728.0 ft, but to prevent entry of water up to El. 730.0 ft. The turbine building, which contains no safety-related equipment or piping, is allowed to flood at water levels above the Standard Project Flood in order to reduce the weight of concrete slab which otherwise would be required to prevent floatation. The portion of the auxiliary building basement which houses the charging pumps is protected against flooding to El. 730.0 ft. The remainder of the basement is allowed to flood in order to eliminate hydraulic uplift.

The portion of the screenwell which houses the safety-related river water pumps and engine-driven fire pump is designed to accommodate a flood to El. 730.0 ft, and operation of the pumps is unaffected by the flood.

New fuel is stored in racks in the fuel storage building well above the Probable Maximum Flood level. The bottom of the spent fuel storage basin is at El. 727.3 ft, but the structure is designed so as to be unaffected by the flood.

The recurrence frequency of the Standard Project Flood is estimated by the Corps of Engineers to be once in 1,000 to 2,000 yr. The Corps of Engineers considers the Probable Maximum Flood to be so far beyond reasonable projection limits that it

might be termed a geologic era event. However, the unit will be able to achieve a safe shutdown condition prior to such a flood affecting any safety-related equipment.

2.3.4 Failure of Downstream Dam Gates and Low Flow

The Pittsburgh District of the Corps of Engineers indicates (Attachments "B" and "C" to Section 2.3) that for catastrophic failure of the New Cumberland Dam coincident with minimum flow in the river, the river would revert to an open channel flow condition and the water surface at the intake for the BVPS-1 would therefore drop to a minimum of El. 648.6 ft. The pit floor of the Beaver Valley screenwell is at El. 640.0 ft so that a water depth of 8.6 ft in the screenwell is ensured even for this water extreme condition. This is adequate to supply the required emergency river water flow of 9,000 gpm coincidental with a fire pump demand of 2,500 gpm.

Channel diversions are not discussed. Information on river cutoffs and subsidence may be obtainable from the Corps.

Information on future probable minimum flow conditions may be obtainable from the Corps.

2.3.5 Environmental Acceptance of Effluents

Under normal operating conditions the expected radioactive releases are far below the standards specified in 10CFR20. The effects of these releases are discussed in Section 3.1.7 of the Environmental Report for BVPS-1 and Appendix 11B of the Updated FSAR. The design bases for effluent facilities are described in Sections 2.2.4 and 11.2. Sections 2.1.3 and 2.1.4 discuss surface and groundwater use. A discussion of accidents and their associated radioactive discharges takes place in Section 6 of the Environmental Report for BVPS-2. The BVPS-2 report discusses the total effect of both stations and is therefore, conservative when considering BVPS-1 alone.

2.3.6 Factors Affecting PMF Analysis

The Technical Report, Attachment "A" to Section 2.3, discusses the results of the analysis for determining the standard project and probable maximum flood waters at the BVPS-1 site. This analysis requires establishing three key parameters; the drainage area, rainfall estimate and roughness coefficients for the runoff analyses.

Drainage Area

Figure 2.3-4 depicts the drainage area subdivisions for which hydrographs have been prepared. Each numbered area represents an uncontrolled area and each shaded area is controlled by a dam, as named. All the dams with the exception of Meander and Chautauqua

are operated by the Corps of Engineers. The different routing reaches used in the PMF analysis are indicated by letters. A tabulation of the drainage are values is included in Table 2.3-1. Table 2.3-2 provides a tabulation of the the hourly unit hydrographic values and Muskingum routing coefficients for the identified drainage areas of Figure 2.3-4.

Rainfall

The rainfall used in estimating the PMF is discussed in Attachment "A" to Section 2.3.

Since the PMF is a summer type storm it would be most likely to occur during a period when rainfall is normal or below, antecedent stream flow would also be low and infiltration loss to runoff high. The infiltration rates computed for the high intensity storm of August 3, 1964, which occurred over the French Creek basin, were used in the Probable Maximum Precipitation (PMP) computations. This storm possessed typical antecedent characteristics under which the PMP storm is generated. These infiltration rates were applied to several high intensity summer storms that occurred in or near the Stonewall Jackson Lake area, and the losses were found to be in close agreement to the actual losses. The infiltration rates used for the PMF are shown in Figure 2.3-15.

Curves for rainfall-excess plotted against precipitation for six-hour periods, contained in "Interim Report on Storms in the Kansas City District", Appendix C, U. S. Army Corps of Engineers, Kansas City Engineer District, May-June 1951, were considered suitable for use in the Standard Project Flood study. These curves, shown in Figure 2.3-16, take into account the probable variation in rainfall over a six-hour period.

Roughness Coefficient

The roughness coefficients were developed using the floods of record. A cross section of the site was drawn and the energy gradient was determined from the flood profiles. A value for "n" in the Manning equation was then computed. The analysis was made at two different sites in the vicinity of Shippingport with a resulting "n" value of 0.035.

Analysis Methodology

Locations of the flood control projects in affect in 1972 above the BVPS-1 site are shown in Figure 2.3-5. Pertinent data relative to these projects is listed on Table 2.3-5. Detailed information is available in the extracts from Reference 17 which are presented as part of Amendment 2 of the Beaver Valley Power Station Unit 2 PSAR (Docket No. 30-412). The distances from Shippingport to the dam sites is presented in Table 2.3-3.

Figure 2.3-6 shows a cross section of the Ohio River at the Shippingport intake. The contours used to estimate the Standard Project Flood and the Probable Maximum Flood may be developed from Figures 2.3-7 through 2.3-13. The El. 740 ft and 760 ft contour lines were taken from the 7.5 minute Midland and Hookstown USGS Quadrangles. A plan view of BVPS-1 showing the containment, turbine building, and other structures is shown in Figure 1.2-1. Elevation views of the containment are shown in Figures 5.1-5 to 5.1-7. Figure 2.3-14 provides a drawing showing historic high water marks.

After the flow hydrograph for the probable maximum flood was computed, a stage-discharge relationship was developed which would accommodate this flow while maintaining all of the hydrologic characteristics. These characteristics require that the valley storage reflect inflow and outflow into any reach and that the stage-discharge relationship adequately represent the computed flows.

When analyzing a particular reach, the valley storage was the average volume within that reach as defined by an average of the upstream and downstream stages. Stage capacity relationships for these reaches had been developed from which a height was determined which would equal the maximum volume stored within that reach representing the difference between the inflow and outflow. A water surface profile was established from these computations and is shown in Figure 2.3-17. The slope of this profile was then inserted into Manning's equation along with the other known values to compute a discharge. This value is then checked against the probable maximum flood peak to satisfy all of the requirements.

The validity of the runoff model used to estimate the Probable Maximum Flood can be demonstrated by Figure 2.3-18 and Table 2.3-4. Figure 2.3-18 shows a comparison of actual and reproduced Ohio River flow rate at the Dashields Lock and Dam during the October 1954 flood. Table 2.3-4 shows one page of the flood forecast.

2.3.7 Seismically-Induced Flood Potential

An evaluation of the seismically-induced flood potential was performed as recommended by Reference 18 for two postulated events:

1. An earthquake of worst historical severity coincident with a standard project flood

2. A safe shutdown earthquake coincident with a 25-year flood.

This analysis requires establishing four parameters, the historic and DBE earthquake values, and the pool levels and reservoir

storage capacities for the 25-year flood and Standard Project Flood.

The design basis earthquake for the station has been established as 0.125 g at the ground surface. The site is blanketed by about 100 ft of alluvials (river terrace gravels). This value corresponds to an earthquake intensity of about VII, Modified Mercalli (MM) scale, according to the Hershberger relations, USGS Bulletin 1279[1]. This is about two orders larger than the historic earthquake of record, which was the Charleston, S.C., earthquake of August 31, 1886, the intensity in the general area historically being IV-V, MM. The value of the DBE was arrived at by determining a conservative value of bedrock motion and then computing amplification through the overburden. Values from this analysis, Appendix 2D, are:

DBE - Motion at surface = 0.125 g

Motion at top of rock = 0.035 g

For this historic earthquake, these would be about two orders less, which, for the Modified Mercalli scale, is a factor of four. Thus, for this historic earthquake, values would be:

At rock surface = 0.01 g

At ground surface = 0.03 g

These values are consistent with observed intensities in the area.

Significant dams on streams tributary to the Ohio River, above the site, are all flood control structures designed by and constructed under the supervision of the Pittsburgh District of the Corps of Engineers. In addition, there are several navigation dams on the river and its principal tributaries, and a few small water supply projects. Navigation dams are essentially gate structures. The gates are closed only during periods of low flow and are wide open during flood periods. Storage capacities are negligible.

At the time of the analysis, 13 flood control projects had been completed. Pertinent features are listed on Table 2.3-5. Shown on this table are reservoir levels and storage capacities for the 25-year flood and the Standard Project Flood for each. Locations of the various dams are shown on Figure 2.3-5. It will be noted that all dams are not on separate tributaries, and, thus, failure of any one dam cannot affect another.

Basically two types of construction have been used, either concrete gravity or rolled fill embankments. In general, zoned construction with central impervious core designs have been used for embankment dams. There are no hydraulic fill structures.

only two of the four area roof drains were capable of passing water, the total accumulation would be less than 13 inches.

In order for this roof to also provide full storage to the parapets, only a 7.5 percent increase in minimum yield strength of the deck material need be assumed. Even if this roof is assumed to fail, detrimental effects are anticipated since any water deposited in the office and air conditioning areas would run out to the ground level below. In this situation, only minor seepage to the switchgear area would occur through the stairway in the clean shop.

All roof and surface drainage around the site passes on directly to the storm drainage system which slopes northward, as shown in Figure 2.3-25, until it discharges into the Ohio River at the intake structure. The site grade of El. 735 ft essentially forms a plateau surrounded on three sides by lower ground; to the north by the lower plant level at El. 705 ft (north of the turbine building) and thereon sloping to the Ohio River (pool level El. 664 ft); to the east by sloping ground to Peggs Run and to the south by a gully formed by the New Cumberland Pennsylvania Railroad. The west end of the plant borders on the former Shippingport Atomic Station site which has a similar site grade of El. 735 ft and the same topographical features to the north and south as for BVPS-1 and sloping ground to the Ohio River to its west.

For rainfall intensities greater than the 4 inches per hr used for the design of the yard drainage some puddling will occur. However, since the site pitches through natural drainage lines, to the Ohio River and Peggs Run, surface drainage will aid the yard storm drainage system in minimizing the buildup of water to less than a few inches.

2.3.11 Low River Flow

A low flow frequency curve for the Ohio River at Shippingport is shown in Figure 2.3-1. This curve represents the lowest continuous seven day mean flows that would occur. It is based on a statistical analysis of historical flows during the past 44 years (1929-1973) as modified by the present reservoir system. An instantaneous low flow could be slightly lower, but with the large impoundments behind the locks and dams, the seven day flow could be provided continuously by temporarily drawing on the river storage when needed.

The lowest flow of record occurred during the extreme drought of 1930. A minimum of 1,250 cfs flowed past Shippingport in August of that year. Since that time eight reservoirs with low flow augmentation capabilities have been constructed. The lowest flow that would have occurred in 1930 with the contemporary reservoir system in 4,000 cfs.

Several reservoirs in the authorized or planning stages (in 1973) would have a substantial influence on low flows. Included in this group are Stonewall Jackson, Rowlesburg, and St. Petersburg. Collectively, they would increase the minimum flow to approximately 6,000 cfs at Shippingport.

The revised minimum flow of 4,000 cfs, as discussed in Reference 19 attached to Section 2.3, results in a reduction of the minimum water surface elevation at the BVPS-1 site to El. 648.6 ft from the previous El. 649.0 ft. The following margin remains for safety-related pumps in the intake structure:

	Submergence at El. 648.6 (ft)	Minimum Submergence Required (ft)	Margin (Percent)
River Water	8	4	100
Fire Pump	5	1.6	210

By extrapolating an unregulated low-flow frequency for drought conditions, which may be characterized as the most severe reasonably possible at the plant site, an instantaneous low flow of about 800 cubic feet per second could occur. This condition was analyzed as discussed below.

Information on the regulation of the New Cumberland Pool during extreme low flow conditions was requested from the Pittsburgh District, Corps of Engineers (Attachments "D" and "E" to Section 2.3).

At a flow of 800 cfs coincident with lock damage, which could reasonably be expected to occur, the pool would drop 1.8 ft to El. 662.7 ft M.S.L.

The New Cumberland Pool is maintained at El. 664.5 ft through the use of locks, dams, and storage reservoirs in the river basin. Records indicate that this elevation can be maintained at flows up to 20,000 cfs.

Normal plant operation can be continued at river levels between El. 695 ft and El. 654 ft. At El. 695 ft, the plant is shutdown as required by the Technical Specifications on rising water level. At El. 654 ft, the river water, raw water and fire water pumps still have adequate NPSH to meet design requirements as summarized below:

The response spectra shown in Figure 2.5-1 and 2.5-2 were the basis for the design of all ground supported structures, equipment, and piping prior to 1979.

As part of the reanalysis of Seismic Category I piping systems, the response spectra shown in Figures 2.5-4 and 2.5-5 were developed using Soil Structure Interaction Methodology. The licensee now considers that the SSI-ARS forms the present and future design basis of the plant.

Amplified response spectra are used for the design of equipment, piping, and instrumentation supported from structures (See Appendix B).

The structures, systems and components designated Seismic Category I as defined in Appendix B are designed for seismic loading as represented by the seismic response spectra. Horizontal and vertical loadings are applied simultaneously. The methods employed to obtain the shear moduli, G, at very small strains, of the soils supporting the structures of the station are determined primarily from direct field measurements of shear wave velocities (Appendix 2G). Under earthquake motion, shear moduli are reduced in accordance with the discussion and appropriate figures of Appendix 2D. Figure 2.5-3 shows values of G for structures founded on or in the upper terrace considering earthquake strains. Shown also in this figure are shear moduli computed from observations of settlement of the turbine room, Shippingport Power Station, for a period of two years. Observation of tests has shown the dynamic or very short time modulus to be about 1.5 to 2.0 times the static modulus. The range of these values are shown and agree very well with the data from seismic shear wave measurements. Average reduced shear moduli considering strains under seismic conditions for the structures at the site are as follows:

1.	Containment Structure	G = 22,000 psi
2.	Fuel Building, Auxiliary Building, and Other Near Surface Buildings	G = 17,000 psi
3.	Intake Structure	G = 17,000 psi

Shear moduli are incorporated in dynamic analyses using the Bycroft solution for dynamic response of a rigid cylindrical base supported on an elastic half space. In using this solution for a specific problem, consideration must be given to the effects of geometry and assumptions implicit in the solution which affect computation of the spring constants, virtual mass of soil moving with the base and scatter in experimental data.

2.5.3.1 Factors Affecting Spring Constant and Mass

Factors affecting spring constant and mass include embedment, effects of limited depth of elastic stratum and effects of actual contact pressure on the base of a structure as compared with distribution assumed in the Bycroft solution. Certain of these factors increase the stiffness and thus, increase the spring-mass ratio while others decrease it. Present technology does not afford definitive solutions.

However, the approximate range effect of each has been established. The elastic half space of the Bycroft solution is weightless and thus, the mass of the soil moving with the structure is ignored. For the containment structure, the virtual mass of soil is estimated not to exceed about 30 percent of the total rotary inertia for rocking and about 18 percent for swaying and may be somewhat less. Since the range of each factor and the effect on the spring-mass ratio are known, it is convenient in estimating the overall range of uncertainty to adjust each spring constant or mass by half the range for the selected factor and then add an uncertainty plus or minus to give the full range. This leads to the following:

	Range of Effect	Equivalent
Embedment	0 to +20%	1.1*(k1, k2-) ±10%
Limited Depth		
Swaying	0 to +20%	1.1*(k1, k2-) ±10%
Rocking	0 to +10%	1.05*(k1, k2-) ±5%
Contact Pressure Distribution		
Swaying	0 to -15%	0.92*(k1, k2-) ±8%
Rocking	0 to -30%	0.85*(k1, k2-) ±15%
Virtual Mass (For Reactor Containment)		
Swaying	+10 to +18%	1.14*(M) ±4%
Rocking	+15 to +30%	1.22*(Iθ) ±8%

Rocking determines the fundamental and dominant mode of the containment structure. Accordingly, for this mode:

$$k/I\theta = 1.1*1.05*0.85*(k1,\ k2-)/(1.22*I\theta)\pm 20\%$$
$$= 0.8*(k1,\ k2-)/I\theta \quad \pm 20\% \qquad (2.5\text{-}1)$$

where k1, k2- are spring constants from the Bycroft solution. Since G (shear modulus) is linear in this solution, a G-equivalent may be computed and used directly in the Bycroft solution.

2.6 SOIL MECHANICS

2.6.1 Site Conditions

The site is located approximately 550 ft east, that is, upstream of the former Shippingport Power Station. The general site area was investigated for foundation conditions in 1954 for foundations for the Shippingport Power Station. The site occupies three terraces along the south side of the Ohio River. The southernmost terrace is the highest at about El. 735 ft and is composed of granular soils. This is also the oldest terrace. Its northerly position was removed either partially or possibly completely to bedrock prior to emplacement of the intermediate and low terraces, the low terrace being the most recent. These lower terraces have cohesive soils near surface overlying granular soils.

Thirty-five dry sample borings were made for the Shippingport Power Station at locations as shown in Figure 2.6-1, under the direction of Stone & Webster Engineering Corporation, and detailed records of the borings and investigations were available for review. These original, rather widely spaced borings have been supplemented by 30 additional borings made specifically for the purpose of the Beaver Valley Power Station. These included 10 dry sample borings on the high terrace, in three of which attempts were made to obtain undisturbed samples with a Denison sampler. The remaining borings were located in the intermediate and low terrace materials, from which undisturbed samples of surface clays and silts were obtained for physical testing. The locations of these various borings are shown on Figure 2.6-1. A log for boring 101, which is typical of the containment structure, is shown in Figure 2.6-2. The Report on Foundations for the Shippingport Power Station, dated August 9, 1954, is included as Appendix 2E. Logs of all borings and results of soil tests made in these investigations are included in Appendixes 2F and 2H.

2.6.2 Subsurface Conditions

2.6.2.1 High Terrace

Ground surface in the area of the proposed station location is at approximately El. 735 ft. The ground underlying this portion of the site is an old, high level terrace of the Ohio River. It is composed of granular material, sands, and sands and gravels, containing variable amounts of cobbles and rock fragments. Some of the material has a silt or clay binder. However, no lenses of silt or clay were encountered in the boring operations and the granular soils extend to bedrock. In general, the materials of the terrace are pervious. There was a continuous loss of drilling water or drilling mud during the drilling operations. Blow counts in the standard penetration test indicated the upper 15 ft approximately of the terrace was looser than the deeper lying material and of somewhat finer grain size. Beginning at

about the south side of the turbine building, this old terrace was either partially or completely removed by erosion in times past and two lower terraces consisting of silt and clay in their upper portions and sands and gravels below about El. 655 to 660 were emplaced by the river. These are in part overlain by granular fills placed for roads and railroads for construction access during construction of Shippingport Power Station.

Bedrock is horizontally bedded shale which was encountered at approximately El. 635 ft. The surface of the bedrock under the station site and out under the river is nearly horizontal. Approximately 1,000 ft south of the station site is the true valley wall where the bedrock surface rises steeply to approximately El. 1,000 ft. A typical subsurface profile section through the station site along an approximately north-south axis looking west is shown in Figure 2.6-3.

Similar foundation conditions exist under the Shippingport Power Station site. This station was founded directly upon the gravels of the high level terrace using mat type foundations. Settlements have been nominal and well within acceptable tolerances.

Profile drawings of all seismic Category I structures and buried river water lines showing subsurface materials to bedrock are included as Figure 2.6-15, 2.6-16, 2.6-17 and 2.6-18.

Attempts made in the investigation to secure undisturbed samples of the soils under the site by using 4 inch diameter Denison samplers were unsuccessful, probably because of difficulties with gravel and rock fragments contained throughout the gravel mass. Accordingly, all conclusions are based on behavior of the existing station and on the results of standard penetration tests made during these and the previous investigations. Plotted in Figure 2.6-4 are the results of standard penetration tests made for the borings located in the high terrace, both for these and for the previous investigations. In general, from the ground surface of the high terrace down to water level, increasing resistance values are shown ranging from approximately 15 near the surface, where the soils were somewhat looser, to approximately 20 at about El. 715 ft and then in a generally increasing trend to the groundwater level at El. 666 ft, where the median blow count is about 57. Approximately at the groundwater table there was a sudden reduction in driving resistance and then a gradual increase in resistance until bedrock was reached. The reason for this marked difference in driving resistance is not known.

There is no significant change in character of material above and below the groundwater table. A possible explanation is the fact that many of the soils contain a greater or lesser amount of silt and clay binder and, above the groundwater table, this material was in partially dry state and therefore, more resistant to

deformation and to shear than if it were completely submerged. Ground water table at the time of these investigations was El. 666 ft, approximately 1 ft above river level. In general, the lower blow counts both above and below the groundwater table occurred in lenses of uniform, medium sands and the higher blow counts in the more gravelly materials.

2.6.2.2 Intermediate Terrace

The intermediate terrace ground surface, about El. 685 to 700 ft, is intermediate in age between the low and high terraces. The upper soils consist of medium clays which extend to about El. 660 ft. This terrace is overlain in part by fill placed in connection with construction of the Shippingport Power Station. It is underlain by sands and gravels which extend to bedrock.

The clay of this terrace north of the turbine building was sampled using 3 inch diameter thin wall samplers (Reference Borings 108 through 113). Quick shear tests made on essentially undisturbed samples of these clays showed shear strengths varying from about 800 to 1,250 psf, with some samples showing shear strengths in excess of 2,000 psf and one sample a shear strength of 500 psf. Stress strain curves from unconfined compression tests are included in Appendix 2F. For several of the samples, the soils were thoroughly remolded at constant water content, formed into cylinders and tested in unconfined compression. Quick shear strengths in the remolded state were about half that of the undisturbed state showing these soils to be of low sensitivity, having a sensitivity ratio of about 2. They are therefore, not susceptible to flow slides under dynamic loadings.

2.6.2.3 Low Terrace

The low terrace, ground level about El. 675 ft, is the most recent. Near surface soils consist of soft clays and clayey silts, many showing some organic contents. Soil test data for these soils are shown in Appendix 2H for borings 304 through 310. Included are both unconfined compression tests and consolidated undrained triaxial tests. Quick shearing strengths of the cohesive members of these soils are quite low, ranging from 160 psf to 440 psf and averaging about 250 psf. These recent river silts and clays extend down to about El. 655 ft where they are underlain by sands and gravels which extend to bedrock at about El. 625 ft.

2.6.3 <u>Foundation Design</u>

2.6.3.1 Foundations

Approximate founding elevations of the more important structures of the station are shown in relation to the soil structure on Figure 2.6-3. The reactor containment structure is founded on a 10 ft thick reinforced concrete mat at approximately El. 681. ft.

This structure has a dead load weight of approximately 7,300 psf over the area of its mat. Relief of load due to excavation of material from the present ground grade of El. 735 ft to El. 681 ft amounts to approximately 6,500 psf. Thus the net added dead load of this structure over its area is only approximately 800 psf. The fuel building, auxiliary building and main control area in the service building are founded upon reinforced concrete mats at about El. 720 ft. As previously indicated, the upper portion of the high level terrace is somewhat lower in density than the remainder. These looser soils, where encountered below founding level, were removed and replaced to founding grade with select compacted granular fill. The dead load of the control area and auxiliary building is approximately 800 to 1,000 psf in excess of the weight of material excavated. These structures therefore, impose small additional loads upon the soil. The average load under the fuel building is approximately 4,000 psf and accordingly it imposes an added load on the soil of approximately 2,000 psf.

As indicated on the section, the surface of the old terrace gravels slopes downward under the turbine building. Surface soils are recent deposits of clay and silt and some fill which has been placed in this area. These were removed to the surface of the stable gravels and replaced with select compacted granular fill under the turbine room and transformers as shown in Figure 2.6-3. This fill material was compacted using heavy vibratory compactors to a minimum density of 95 percent of Modified Proctor, ASTM D1557. Maximum soil pressures for static loadings are 8,000 psf for foundations on granular soils at depths of 8 ft or more below surrounding grades. Under lateral loadings such as from wind and earthquake, toe pressure under combined dead loads and lateral loads is limited to 12,000 psf. These are conservative and safe values for granular materials of this character.

The Shippingport Power Station site and the Beaver Valley Power Station are both located on the same large continuous terrace on the left (south) bank of the Ohio River. The boring program for Shippingport, which was made under the direction of S&W, extended well upstream and downstream of the site and thus bracketed borings for the Beaver Valley Power Station. Soil types and penetration resistances were consistent between the two sets of borings (Refer to Figure 2.6-4 where data from both the Shippingport borings and Beaver Valley borings are plotted). This terrace is a single, continuous structure all of the same age and made of deposition. Since it is of fluvial origin, stratification and cross-bedding are to be anticipated and are indicated by the boring records. Thus while variations in character may occur in a few inches vertically and a few feet horizontally, it is statistically uniform over depths and lateral dimensions significant to the foundations of the structures. Maximum bearing values for foundations in the sand and gravel below El. 715 ft at Shippingport and subject to groundwater levels were established at 8,000 psf for footings 8 ft or deeper

below surrounding grade. Settlements have been small and performance completely satisfactory.

The natural draft cooling tower is located on the northeast corner of the site along the edge of the river. It is founded on well compacted granular fill placed to El. 700 ft. The soft, compressible silts, organic silts and clays were removed in this area to approximately El. 655 ft and/or the top of the lower gravels, prior to the placement of the structural fill under the tower. These precautions insured against any settlements or failure in the poorer soils. The structural fill for this purpose was compacted to 97 percent of a Standard Proctor Density Test, ASTM D698. In some areas surrounding the site, a nonstructural fill was used to fill in the recessed areas. These materials were compacted to 93 percent of a Standard Proctor Density Test. The embankment slope of this fill, exposed to the river, was provided with a concrete slope wall protection to El. 700 ft as a precaution against possible erosion by flooding in this area.

2.6.3.2 Settlement of Structures

The procedure for estimating settlements under the various structures is based on techniques developed in studies of the Alternating Gradient Synchrotron (AGS) at Brookhaven National Laboratory (BNL). Basically, the procedure is analogous to estimating displacements at the surface of an elastic mass due to an applied surface loading. Briefly, the additional stress of any element within the soil mass from the applied load is computed. The compression then of each such an element is equal to the increased stress times the height of the element divided by the modulus of deformation. The sum of the deformation of the elements from the bedrock surface to the founding level gives the total settlement at that point. Essentially, thus the modulus used corresponds to the modulus of elasticity in elastic analysis. Since, however, soils are not truly elastic, we prefer to call it a modulus of deformation and designate it by the symbol M. It is not a coefficient of subgrade reaction. The observed settlements of the turbine room of the Shippingport Power Station, which is founded upon the same soils and at approximately the same elevation as the containment structure and turbine building of the BVPS-1, provide an excellent large scale load test for determining the deformation modulus. Settlement plates were set under the Shippingport turbine room mat before starting to pour it. Extending up from each settlement plate was a rod which was isolated from the mat by a pipe sleeve. Initial settlement records were taken before the start of pouring the mat which began in September of 1955 and observations were continued on a more or less regular basis until August of 1957, approximately a year after all loads had been placed. Figure 2.6-5 shows the location of the settlement observation points under the Shippingport turbine room, mat and the observed settlements in December 1956, approximately 15 months after start

of construction and in August of 1957, approximately 23 months after the start of construction of the mat. Very little settlement occurred between December, 1956 and August, 1957, indicating that both primary and secondary settlements were essentially complete at the time of the last settlement observation. Observations at the Brookhaven National Laboratory on the AGS and other structures and at Shippingport have indicated there is an immediate primary settlement followed by a secondary settlement of some duration even for sand soils.

It has been known for some time that the modulus of deformation of granular soils varies with the effective stress. The studies at BNL showed that approximately:

$$M = K \sqrt{Z + A} \qquad (2.6\text{-}1)$$

where: Z = depth below surface (position down)

K = a constant depending on soil properties

A = a constant whose value is such that the resulting value of M is approximately 1.5 to 2.0 x $10^{(6)}$ kips per sq ft at the surface

Using the observed long-term settlements at Shippingport, it is possible to compute the modulus of deformation "M" of the soils at Beaver Valley for long-term loadings. This is shown in Figure 2.6-6. Observations made during construction of the conjunction section at the AGS and observations on large scale loading tests at BNL on areas approximately 30 ft square shows that the modulus of deformation for a reloading cycle is approximately twice that of the initial loading. Further, the modulus for primary settlement, that is the settlement under very short time loadings as for dynamic loadings is approximately 1.5 to 2.0 times the modulus for long-term loadings.

Using these moduli and relations, average long-term settlements of the principal structures under static loadings have been computed as follows:

1. Containment Structure - 0.5 inches
2. Auxiliary Building - 0.25 inches
3. Fuel Building - 0.25 inches
4. Main Control Area - 0.2 inches

The granular soils as indicated by the grading curves contain some silt and clay binder. Such binder material provides a slight cohesive strength which greatly reduces the tendency of individual grains to shift under vibration. It may be noted that

Figure 2.7-9). The service building area below El. 730 ft is isolated from these flooded areas by the perimeter concrete walls of the service building. All construction joints below El. 730 ft are water stopped and all through electrical penetrations are sealed.

Flooding of the pipe tunnel will result in flooding of the pipe tunnel area of the main steam-cable vault structure, the northern portion of the safeguards structure, and the primary auxiliary building (excepting the charging pump cubicles).

Water cannot enter the cable tunnel since this area is isolated from the rest of the main steam-cable vault area below El. 735 ft by concrete walls and is accessible only from the cable vault area at El. 735 ft.

2.7.3.2.4 Electrical Cable Protection

The cable tunnel is that portion of the service building allowing for transfer of cable from the cable vault structure to the cable tray area within the service building and is seismically designed as indicated in Table B.1-1.

The means for routing cable from the main portions of the plant to the intake structure is through cable ductlines extending from the high level terrace (El. 735 ft) to the lower level terrace (El. 675 ft) which is the ground elevation at the intake structure.

Figures 2.7-10, -11 and -12 show the cable duct from the plant to the intake structure including all manholes. The manholes are below PMF level and are allowed to flood.

The protective measures to prevent flooding in areas where essential equipment for cold shutdown is located, will be duct or sleeve sealed. This sealing will be required where ductlines enter the intake structure and on the south end of the ductline at the service building.

The water barrier, where the cable tunnel, which is an extension of the ductline from the intake structure to the plant, interfaces with the service building, is shown in Section 1-1 of Figure 2.7-13.

All cables for 4 kV service, 480 V service, control and instrumentation for both primary and secondary plant use are of the same high quality construction. Each type of cable has been specified for use in wet and dry locations and will operate satisfactorily if submerged as proven by factory testing. The 4 kV power cable was submerged for a period of 24 hours before testing at the supplier's factory.

Where cables pass through penetrations into an area where safety-related equipment is located, and where these penetrations are

below PMF level, sealing methods were implemented. These sealing procedures will make the penetrations leak resistant and will use materials which have been employed in the past, or newly developed methods.

The 5 kV cables installed in underground ductlines from the service building to the diesel generator building and to the intake structure are adequate for the intended service when these cables are operating under wet or dry conditions. The same qualification covers any splices. Wet conditions include immersion under water. The cable referred to above has an insulation thickness greater than that required by the Insulated Power Cable Engineers' Association[7].

Duquesne Light Company has had several occasions whereby 5 kV cable raceways have been flooded with water and no failure has resulted. This was experienced within the past several years at the Cheswick Power Station. The Brunot Island Station also has had high voltage cables completely submerged on several occasions, including the 1936 flood, without failures. The cable as selected is suitable for operation in a ductline under wet or dry conditions; wet conditions are considered with cables immersed in water. Cables will be proof-tested prior to initial energization, and no further periodic testing is contemplated unless the cable has been exposed to an abnormal condition.

2.7.3.2.5 Other Plant Areas and Equipment

Water from the PMF could enter a 4 inch shake space between the service building and the turbine building. The openings through the service building north wall have wall sleeves as shown in Figure 2.7-14. Details of closures are shown in Figures 2.7-15 and -16. Closures plates are shown in Figure 2.7-15 with sleeve details shown in Section "A-A". The seals for the 4 kV cable bus, Figure 2.7-16, are Nelson "Multi-Cable Transits" which are watertight.

Flood protected areas have been indicated on Figures 2.7-17, -18, and -19. Floors and walls within these areas are constructed with concrete. Penetrations, such as pipes, which enter these areas and are embedded in concrete, utilize water stops to prevent inleakage. All penetrations which enter through the openings in the concrete are sealed after installation of the item by using one of the methods illustrated on Figure 2.7-19. Where banks of wall sleeves for electrical cables enter protected areas, the sleeves are O-ring sealed to a galvanized steel plate. The plate is bolted and gasketed to the wall as shown on Figure 2.7-18. The cables are sealed within the sleeve, using cellular concrete as shown on Figure 2.7-19.

Water barriers and sealing materials consist of concrete, steel plate, cellular concrete, nylon or fiberglass reinforced rubber,

neoprene rubber, and pump shaft seal materials. With the exception of the pump seals, all water barriers are in a static condition, do not contact rotating parts of equipment, and are not located in a hostile environment. Experience has shown that all of these materials have a long life under these conditions, and degradation over the life of the plant, which would reduce their adequacy as a water barrier, is not expected. Pump shaft seals which are subject to wear will be replaced as required by operation or testing of these seals.

All flood penetration sealing methods shown on Figure 2.7-19 will be preoperationally and periodically tested to ensure that the techniques used are adequate. This is accomplished by simulating actual seal configurations and subjecting one side of the seal to a hydrostatic pressure of 125 percent of the PMF conditions. A leakage rate of 0.04 gpm is considered acceptable. This leak rate is based on the worst case which is the service building north wall containing approximately 200 penetrations. This ensures that the sump pump has a capacity with a minimum safety factor of 2 to 1.

All pumps in the intake structure are preoperationally and periodically operated during which their seals are checked for seal water leakage. Any abnormal seal water leakage would be noted during testing of the pumps and the seals would be repaired or replaced.

All flood protected areas have sumps or 12 inch high curbs along walls containing sealed penetrations. Any inleakage which would occur during a PMF would be collected in these areas. All sumps and curbs contain either a float-actuated sump pump or a level switch and transmitter with a control room alarm. Portable sump pumps are provided which can be used, wherever needed. Emergency power supply connections are located at each wall curb, and each permanent sump pump is connected to the emergency power supply.

The control room air conditioning room is protected from flooding by a manually-operated gate valve in series with a check valve in the six-inch drain line from the control room air conditioning room. The gate valve, labeled back water valve VGF-12D, is located in the turbine building at El. 698 ft-6 inch. This valve will be closed when river level reaches El. 695 ft. Since the turbine building does not begin flooding until the river reaches El. 707 ft-6 inch, there is adequate time to operate this valve prior to turbine building flooding when this valve would become inaccessible. During the PMF condition, this valve will not be operated, but will only be opened following the flooding event. Internal flood protection of the control room air conditioning room with the drain line gate valve closed is discussed in Section 9.7.2.

Flood sealing methods used for penetrations below El. 730 ft protecting safety-related equipment during a PMF, were tested at initial installation. In addition, each penetration with a flood seal shall receive a periodic visual inspection.

To ensure that all penetrations are sealed, walls required as a flood barrier are given two independent visual checks. Entire walls are checked as opposed to individual penetrations on a list to preclude the possibility of a new penetration being left off a list and not being inspected.

The charging pump cubicles are designed against ingress of water during a PMF. Any penetrations below El. 730 ft are sealed with a technique shown on Figure 2.7-19. The ventilation duct enters the charging pump cubicles with the bottom of the duct at El. 731 ft 9 inches. There is also a horizontal slot in the north wall of the charging pump cubicles through which piping passes. The bottom of the slot is at El. 730 ft 6 inches.

The charging pumps, Figures 2.7-20 and 2.7-21 (circled), are enclosed by walls that are missile-proof and are extended to El. 730 ft-6 inches, which is 6 inches above the PMF level. The six conduits that penetrate the walls were sealed in accordance with the results of the sealing study.

2.7.4 Soils Design Loading

The looser granular material above El. 715 ft in the containment structure area and the silty sands and clays in the turbine building area were removed and replaced by compacted granular material (Section 2.6). The compacted granular fill is composed of selected sands and gravels and compacted in 6 inch layers to a minimum density of 95 percent as determined by modified compaction tests performed in accordance with ASTM D1557.

Foundations for all major structures are continuous mats of reinforced concrete founded on the denser undisturbed gravels or compacted granular fill. The containment structure is founded at El. 681 ft on undisturbed gravel and compacted granular material, with excavation below El. 715 ft made within a circular sheet piling cofferdam. The turbine building mat with bottom at approximately El. 683 ft is located in part on undisturbed, inplace gravel and in part on compacted granular fill.

The current environmental radiological monitoring program (REMP) requirements are documented in the Offsite Dose Calculation Manual (ODCM). The ODCM contains the site number, sector, distance, sample point, description, sampling and collection frequency, analysis, and analysis frequency for various exposure pathways in the vicinity of the Beaver Valley Power Station (BVPS). These are the minimum requirements for the REMP program and may be supplemented with additional samples, increased collection frequency, and increased analysis requirements. Environmental sampling and analyses include air, water, milk, vegetation, river sediments, fish, soil, and ambient radiation levels in areas surrounding the site.

The results of the REMP program are documented and submitted to the NRC each year in the Annual Radiological Environmental Operating Report.

SECTION 3

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Figure 3.4-11	Revision 0	January, 1982
Figure 3.4-12	Revision 0	January, 1982
Figure 3.4-13	Revision 0	January, 1982
Figure 3.4-14	Revision 0	January, 1982
Figure 3.4-15	Revision 0	January, 1982
Figure 3.4-16	Revision 0	January, 1982
Figure 3.4-17	Revision 0	January, 1982
Figure 3.4-18 (Deleted)	Revision 16	January, 1998
Figure 3.4-19 (Deleted)	Revision 16	January, 1998
Figure 3.4-20 (Deleted)	Revision 16	January, 1998
Figure 3.4-21 (Deleted)	Revision 16	January, 1998
Figure 3.4-22	Revision 16	January, 1998
Figure 3.4-23	Revision 0	January, 1982
Figure 3.4-24	Revision 0	January, 1982
Figure 3.4-25 (Deleted)	Revision 8	January, 1990

SECTION 3

REACTOR

3.1 SUMMARY DESCRIPTION

This chapter describes:

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

3. the thermal-hydraulic design

The reactor core is comprised of an array of 17 x 17 Standard (STD) and/or VANTAGE 5H (V5H) fuel assemblies.

The significant new mechanical design features of the VANTAGE 5H fuel assembly design are described in References 1 and 2. These features include the following:

- Integral Fuel Burnable Absorbers (IFBAs)

- Axial Blankets - The axial blanket region is the nominal 6 inches of fuel pellets located at each end of the fuel rod pellet stack. The fuel pellets in the axial blanket region may be natural, mid-enriched or fully enriched solid or annular pellets. The annular blanket pellets are used to increase the void volume for gas accommodation within the fuel rod.

- Replacement of six intermediate Inconel grids with Zircaloy grids

- Slightly longer fuel rods and thinner top and bottom nozzle and plates to accommodate extended burnup

- Reconstitutable Top Nozzles (RTNs)

- Redesigned fuel rod bottom end plug to facilitate reconstitution capability

- Reduction in guide thimble and instrumentation tube diameter

Beginning with Beaver Valley Unit 1 Cycle 13, features of the VANTAGE+ fuel assembly design were incorporated into the fresh fuel feed regions. The VANTAGE+ fuel assembly design (Reference 5) included the following features: ZIRLO™ clad fuel rods, thimble tubes, and instrumentation tubes. The intermediate grid strap material was also changed to ZIRLO™. As an added debris mitigation feature, a protective bottom grid was incorporated.

The core is cooled and moderated by light water at a pressure of 2250 psia in the Reactor Coolant System. The moderator coolant contains soluble boron as a neutron poison. 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 Integral Fuel Burnable Absorbers (IFBAs) or discrete burnable absorber rods, may be used to limit the moderator temperature coefficient (MTC) and the total power peaking that can be achieved.

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 to increase fatigue life. A protective bottom grid has been added just above the bottom nozzle. The grid straps intersect the nozzle flow holes, thus, further reducing the possibility of fuel rod damage due to debris induced fuel rod fretting. In addition, the ZIRLO™ fuel rods will be oxide coated at the lower end for additional protection against fretting.

Fuel assemblies may also contain non-fueled rods (stainless steel, Zircaloy-4 or ZIRLO™ filler rods). Non-fueled rods may be used in core locations where fuel damage has occurred or may occur. The use of non-fueled rods began when fuel inspections performed during the fifth refueling outage identified leaking fuel rods in a peripheral assembly. It was determined that the fuel rod leakage was attributable to baffle jetting.

The solution to this problem, recommended by Westinghouse and used by other utilities, involves fuel assembly reconstitution as a means to allow the insertion of non-fueled rods into a fuel assembly. In the reconstitution process, the fuel rods in positions subject to problem conditions would be removed and replaced with non-fueled rods. The reconstituted fuel assemblies meet essentially the same design requirement as the original fuel assembly, and the use of reconstituted assemblies will not result in a change to existing safety criteria and design limits. The effects of fuel assembly reconstitution are evaluated in accordance with the methods described in Reference 4.

The VANTAGE 5H fuel assembly design is shown in Figure 3.2-2A. The design changes from the 17 x 17 STD 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 assemblies. The DFBN design 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 5H assembly has the same cross-sectional envelope as the 17 X 17 STD fuel assembly. However, the VANTAGE 5H assembly overall length has been increased to accommodate extended burnup.

The VANTAGE+ assembly skeleton is identical to the VANTAGE 5H assembly skeleton except for those modifications necessary to accommodate the intended fuel operation to higher burnups. The modifications consist of the use of ZIRLO™ guide thimbles, instrumentation tubes, cladding, and small skeleton dimensional alterations to provide additional fuel assembly and rod growth space at the extended burnup levels. The VANTAGE+ fuel assembly is shorter than the VANTAGE 5H fuel assembly. The grid centerline elevations of the VANTAGE+ are identical to those of the VANTAGE 5H fuel assembly, except for the top, first and second grids. The VANTAGE+ top grid and second grid have been lowered slightly and the first grid has been raised slightly. The first and second grids have been adjusted to stiffen the lower span to reduce the likelihood of grid-to-rod fretting failures, in addition to allowing space for the Protective Bottom Grid. However, since the VANTAGE+ fuel is intended to replace the VANTAGE 5H fuel, the VANTAGE+ exterior assembly envelope is equivalent in design dimensions, and the functional interface with the reactor internals is also equivalent to those of previous Westinghouse fuel designs. Also the VANTAGE+ fuel assembly is designed to be mechanically and hydraulically compatible with the VANTAGE 5H fuel assembly. The same functional requirements and design criteria established for the Westinghouse VANTAGE 5H fuel assembly remains valid for the VANTAGE+ fuel assembly. The VANTAGE+ fuel assembly design is provided in Figure 3.2-2B.

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.

3.2.1.2.1 Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in slightly cold worked Zircaloy-4 or ZIRLO™ tubing which is plugged and seal welded at the ends to encapsulate the fuel. Schematics of the 17 x 17 STD, VANTAGE 5H, and VANTAGE+ fuel rods are shown in Figures 3.2-3, 3.2-3A and 3.2-3B. The fuel pellets are right circular cylinders consisting of enriched uranium-dioxide powder which has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly to allow greater axial expansion at the center of the pellets. The fuel rods may also contain annular pellets in the upper and lower six inch axial blanket regions which have no dish on the pellet ends, but are hollow for additional gas volume.

The VANTAGE 5H fuel rod is of the same design as the 17 x 17 STD fuel rod except that the VANTAGE 5H fuel rod is longer to provide a longer plenum and bottom end plug. The bottom end plug has an internal grip feature to facilitate rod loading on both designs. The bottom end plug is also longer to provide an improved lead-in for the removable top nozzle reconstitution feature.

The VANTAGE+ fuel rod represents a modification to the VANTAGE 5H fuel rod intended to support operation for fuel clad in place of Zircaloy-4 clad. The ZIRLO™ alloy is a zirconium alloy similar to Zircaloy-4 that has been specifically developed to enhance corrosion resistance. The VANTAGE+ fuel rods will contain, as in VANTAGE 5H fuel rod, enriched uranium dioxide fuel pellets and an Integral Fuel Burnable Absorber (IFBA) coating on some of the enriched fuel pellets.

The VANTAGE+ fuel rod has the same clad wall thickness as the VANTAGE 5H design. The VANTAGE+ fuel tube is shorter to provide room for the required fuel rod growth. To offset the reduction in the plenum length, the VANTAGE+ fuel rod has a variable pitch plenum spring. This spring has smaller wire and coil diameters and a shorter free length. The variable pitch plenum spring provides the same support as the regular VANTAGE+ plenum spring but with fewer spring turns which translates to less spring volume. The top end plug on the VANTAGE+ fuel rod has an external grip feature to facilitate fuel rod loading. The VANTAGE+ fuel rod also has an oxide coating at the bottom end of the fuel rod. The extra layer of oxide coating provides additional debris induced rod fretting wear protection.

The Beaver Valley Unit 1 17 x 17 STD, VANTAGE 5H and VANTAGE+ fuel may have axial blankets and will use a standardized fuel pellet design.

The standardized fuel pellet design 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 IFBA coated pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boron 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 may vary depending on specific application. The ends of the enriched coated pellets and enriched uncoated pellets are dished to allow for greater axial expansion at the pellet centerline and void volume for fission gas release. An evaluation and test program for the IFBA design features are given in Section 2.5 of Reference 20.

The axial blanket region is the nominal six inches of the fuel pellets at each end of the fuel rod pellet stack that may be natural, mid-enriched, or fully enriched uranium dioxide. Natural and mid-enriched axial blankets reduce neutron leakage and improve fuel utilization. The axial blanket pellets may be either solid or annular. The annular axial blanket pellets are used to increase the void volume for gas accommodation within the fuel rod. The axial blanket pellets are of the same design as the enriched and IFBA pellet designs except for an increase in length. The length difference in the axial blanket pellets will help prevent accidental mixing with the enriched and IFBA pellets.

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 of 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. The helium pre-pressurization may be different for each fuel region. Fuel rod pressurization is dependent on the planned fuel burnup as well as other fuel design parameters and fuel characteristics (particularly densification potential).

The cold helium design pressure for current Westinghouse PWR fuel rods is several hundred psi. The precise design pressure values for BVPS-1 fuel regions depend on detailed performance evaluations. Such detailed design information is proprietary to Westinghouse and will not be included in the Updated Final Safety Analysis Report.

The fuel rods are designed such that 1) the internal gas pressure of the lead rod will not exceed the value which causes the fuel-clad diametral gap to increase due to outward cladding creep during steady-state operation, 2) extensive DNB propagation will not occur, 3) the cladding stress-strain limits (Section 3.2.1.1.1) are not exceeded for Condition I and II events, and 4) clad flattening will not occur during the fuel core life.

3.2.1.2.2 Fuel Assembly Structure

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles and grids, as shown in Figure 3.2-2.

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 in Figures 3.2-2A and 3.2-2B. 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 their fuel assembly. The bottom nozzle is fastened to the fuel assembly guide tubes by locking cup or weld-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 Beaver Valley Unit 1 Region 10 fuel assemblies to help reduce the possibility of fuel rod damage due to debris-induced fretting. The 304 stainless steel DFBN is similar to the conventional bottom nozzle design used previously for Beaver Valley. However, the DFBN design incorporates a modified flow hole size and pattern (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 that 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 hole sizing was also designed to provide sufficient flow area, comparable pressure drop, 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.

life for various modes of operation including load follow, reduced power operation, and axial xenon transients.

Radial power distributions are calculated for the full power condition and fuel and moderator temperature feedback effects are included for the average enthalpy plane of the reactor. The steady state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution effects neglected. The effect of flow redistribution is calculated explicitly where it is important in the DNB analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 3.3-6 and 3.3-7) but is included as part of the normal design process. Radial power distributions are relatively fixed and easily bounded with upper limits.

The core average axial profile, however, can experience significant changes which can occur rapidly as a result of rod motion and load changes and more slowly due to xenon distribution. For the study of points of closest approach to axial power distribution limits, several thousand cases are examined. Since the properties of the nuclear design dictate what axial shapes can occur, boundaries on the limits of interest can be set in terms of the parameters which are readily observed on the plant. Specifically, the nuclear design parameters which are significant to the axial power distribution analysis are:

1. core power level
2. core height
3. coolant temperature and flow
4. coolant temperature program as a function of reactor power
5. fuel cycle lifetimes
6. rod bank worths
7. rod bank overlaps.

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 13 steps (indicated) from the bank demand position
2. Control banks are sequenced with overlapping banks
3. The control full length 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. Briefly 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.

Calculations, as described in Reference 30, 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. These calculated points have been synthesized from axial calculations combined with radial factors appropriate for rodded and unrodded planes in the first cycle. The calculated values have been increased by a factor of 1.05 for measurement error, a factor of 1.03 for the manufacturing tolerances.

The envelope drawn over the calculated F(Q) points in Figure 3.3-21 represents 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. For example, Figure 3.3-21 bounds both BOL and EOL conditions but without consideration of radial power distribution flattening with burnup, i.e., both BOL and EOL points presume the same radial peaking factor. Inclusion of the burnup flattening effect would reduce the local power densities corresponding to EOL conditions which may be limiting at the higher core elevations.

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. These procedures are detailed in the Technical Specifications/Licensing Requirements Manual and predicated only upon ex-core surveillance supplemented by the normal monthly full core map requirements 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 at 2,652 MWt is 5.20 kw/ft. From Figure 3.3-21, the conservative upper bound value of normalized local power density, including uncertainty allowances is 2.40 corresponding to a peak local power density of 12.7 kw/ft at 102 percent power.

To determine reactor protection system set points, 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 banks. Also included are motions of the full length 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%. Since the study is to determine protection limits with respect to power and axial offset, no credit was taken for trip set point reduction due to flux difference. The results are given in Figure 3.3-23 in units of kw/ft. The peak power density which can occur in such events, assuming reactor trip at or below 118%, is thus limited to 22.0 kw/ft for the three loop plant including uncertainties and densification effects.

The second category also appearing in Figure 3.3-23, 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. The results shown on Figure 3.3-23A are F(Q) multiplied by 102% 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 20.0 kw/ft including the above factors. However, the Technical Specifications (COLR) restrict operation with F(Q) such that this peak linear power density is less than 22.0 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 for the reactor described herein 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 described in Technical Specifications. Analyses have been performed for Cycle 8 to increase the F(Q) and $F(N,\Delta H)$ peaking factors from the initial design values of 2.32 and 1.55 to 2.40 and 1.62 respectively.

F(Q) can be increased with decreasing power as shown in the Technical Specifications. Increasing F(N,ΔH) with decreasing power is permitted by the DNB protection set points and allows radial power shape changes with rod insertion to the insertion limits as described in Section 3.4.3.2. It has been determined that provided the above conditions 1 through 4 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.

3.3.2.2.7 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 movable detector system described in Section 7.7.1 and 3.4.5, 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 intercalibrated 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 errors of types (2) and (3) above.

Reference 2 describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurement taken on two Westinghouse plants with in-core 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% at the 95% confidence level with only 5% of the measurements greater than the inferred value. This is the equivalent of a 2 σ limit on a normal distribution and is the uncertainty to be associated with a full core flux map with movable 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%.

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 in Figure 3.3-24 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% uncertainty allowance on F(Q).

A similar analysis for the uncertainty in F(ΔH) (rod integral power) measurements results in an allowance of 3.65% at the equivalent of a 2 σ confidence level. For historical reasons, an 8% uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integral at full power must not exceed the design F(ΔH) less 8%. This 8% may be reduced in final design to 4% to allow a wider range of acceptable axial power distributions in the (Departure from Nucleate Boiling) analysis and still meet the design bases of Section 3.3.1.3.

A measurement in the second cycle of a 121 assembly, 12 foot, core is compared with a simplified one dimensional core average axial calculation in Figure 3.3-25. 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 are obtained part of the ex-core detector calibration exercise which is performed monthly

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

These data are presented in detail in Reference 5. Figure 3.3-26 contains a summary of measured values of F(Q) as a function of axial offset for five plants from the report.

3.3.2.2.8 Testing

A very extensive series of physics tests is performed on first cores. These tests and the criteria for satisfactory results are described in detail in Section 13. Since not all limiting situations can be created at beginning of life, 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. Tests performed at the beginning of each reload cycle are limited to verification of steady state power distributions, on the assumption that the reload fuel is supplied by the first core designer.

3.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration and errors are described in References 2, 4, and 5. The relevant conclusions are summarized here in Section 3.3.2.2.7 and 3.4.5.

Provided the limitations given in Section 3.3.2.2.6 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 Technical Specifications and the Licensing Requirements Manual, together with a discussion of their bases.

Limits for alarms, reactor trip, etc. are given in the Technical Specifications. Descriptions of the systems provided are given in Section 7.

3.3.2.3 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 Chapter 14. The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 3.3.3. These models have been confirmed through extensive testing of abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. These models have been confirmed through

References for Section 3.3 (Cont'd)

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51. W. D. Newmyer, "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," WCAP-14416-NP-A (November 1996).

52. P. J. Kersting, et. al., "Assessment of Clad Flattening and Densification Power Spike Elimination in Westinghouse Nuclear Fuel," WCAP-13589-A (March 1995).

3.4.2.2.3 Gap Conductance (h)

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 the UO_2 thermal conductivity model, the calculated fuel centerline temperatures reflect the inpile temperature measurements.

The temperature drop across the gap is calculated by assuming an annular gap conductance model of the following form:

$$h = \frac{K_{gas}}{\frac{\delta}{2} + 14.4 \times 10^{-6}} \qquad (3.4\text{-}4)$$

or an empirical correlation derived from thermocouple and melt radius data:

$$h = 1500\ K_{gas} + \frac{4.0}{0.006+12\delta} \qquad (3.4\text{-}4a)$$

where

K_{gas} = thermal conductivity of the gas mixture including a correction factor[10] for the accommodation coefficient for light gases (e.g. helium), Btu/hr-ft-°F

δ = diametral gap size, ft.

The larger gap conductance value from these two equations is used to calculate the temperature drop across the gap for finite gaps.

For evaluations in which the pellet-clad gap is closed, a contact conductance is calculated. The contact conductance between UO and zircaloy/ZIRLO™ has been measured and found to be dependent on the contact pressure, composition of the gas at the interface and the surface roughness of the fuel and cladding.[10][33] This information together with the surface roughness found in the fuel and clad installed in Westinghouse reactors leads to the following correlation:

$$h = 0.6p + \frac{K_{gas}}{14.4 \times 10^{-6}} \qquad (3.4\text{-}4)$$

where

h = contact conductance, Btu/hr-ft^2-°F

p = fuel clad contact pressure, psi

3.4.2.2.4 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and nucleate boiling are presented in Section 3.4.2.8.1.

3.4.2.2.5 Fuel Clad Temperatures

The outer surface of the fuel rod clad at the hot spot operates at a temperature of approximately 660°F for steady state operation at rated power throughout core life due to the onset of nucleate boiling. Initially (beginning-of-life) this temperature is that of the clad metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod surface causes the clad surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. Since the thermal-hydraulic design limits DNB, adequate heat transfer is provided between the fuel clad and the reactor coolant so that the core thermal output is not limited by considerations of the clad temperature. Figure 3.4-4 shows the axial variation of average clad temperature for the average power rod both at beginning and end-of-life.

3.4.2.2.6 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. The peak local power at full power conditions is given in Table 3.4-1 and is based on the design value of F(Q) for normal operation. As described in Section 3.3.2.2.6 the peak local power at the maximum overpower trip point is 22.0 kW/ft. The centerline temperature at this power level 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 is assumed to decrease by 58°F per 10,000 MWD/MTU. From Figure 3.4-2, it is evident that the centerline temperature at the maximum overpower trip point is far below that required to produce melting. Fuel centerline and average temperature at rated (100%) power and at the maximum overpower trip point are presented in Table 3.4-1.

3.4.2.3 Critical Heat Flux Ratio and Departure from Nucleate Boiling Ratio and Mixing Technology

The minimum DNBR's for the rated power, design overpower and anticipated transient conditions are given in Table 3.4-1. 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 3.4.2.3.1 and 3.4.2.3.2. The THINC-IV computer code (discussed in Section 3.4.3.4.1) 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 3.4.3.2.1 (nuclear hot channel factors) and in Section 3.4.2.3.4 (engineering hot channel factors).

1. Rod to Rod Variations in Enrichment, Density and Burnable Absorber (F (E, ΔH, I)):

   F (E, ΔH, I) is similar to F (E, Q) except it covers the effect of rod to rod variations. Rod to rod variations are less than pellet to pellet variations and F (E, ΔH, I) will therefore be less than F (E, Q).

2. Inlet Flow Maldistribution:

   The consideration of inlet flow maldistribution in core thermal performances is discussed in Section 3.4.3.1.2. A design basis of 5% reduction in coolant flow to the hot assembly is used in the THINC-IV analysis.

3. 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 non-uniform power distribution is inherently considered in the THINC analysis for every operating condition which is evaluated.

4. Flow Mixing:

   The subchannel mixing model incorporated in the THINC Code and used in reactor design is based on experimental data[42] discussed in Section 3.4.3.4.1. 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.

3.4.2.3.5 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in Reference 86 must be accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application.

The safety analysis for BVPS-1 maintained sufficient margin, as discussed in Section 3.4.1.1, to accommodate full and low flow DNBR penalties identified in References 86 and 87 (<1.3 percent for the worst case which occurs at a burnup of 24,000 MWD/MTU).

The maximum rod bow penalties accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of F(N, ΔH) burndown due to the decrease in fissionable isotopes and the buildup of fission product inventory, and no additional rod bow penalty is required[89].

3.4.2.4 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 RCCA could cause changes in hot-channel factors; however, these events are analyzed separately in Chapter 14. This discussion will be confined to flux tilts caused by X-Y xenon transients, inlet temperature mismatches, enrichment variations within tolerances and so forth.

The design value of the enthalpy rise hot-channel factor F(N, ΔH) which includes an 8% uncertainty (as discussed in Section 3.3.2.2.7), is assumed to be sufficiently conservative that flux tilts up to and including the alarm point will not result in values of F(N, ΔH) greater than that assumed in this submittal (alarm criteria described in the Technical Specifications and Licensing Requirements Manual). The design value of F(Q) does not include a specific allowance for quadrant flux tilts.

3.4.2.5 Void Fraction Distribution

The calculated core average and the hot subchannel maximum and average void fractions are presented in Table 3.4-3 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 43. The void models used in the THINC-IV computer code are described in Section 3.4.2.8.3.

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 reference above.[43]

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.

3.4.2.6 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 flow distributions are shown for the 4-ft elevation (1/3 of core height) in Figure 3.4-9, and 8-ft elevation (2/3 of core height) in Figure 3.4-10, and at the core exit in Figure 3.4-11. These distributions are for the full power conditions as given in Table 3.4-1 and for the radial power density distribution shown in Figure 3.3-7. The THINC Code analysis for this case utilized a uniform core inlet enthalpy and inlet flow distribution.

from a completely shutdown condition to 120 percent of full power with the capability of recording overpower excursions up to 200 percent of full power.

The difference in neutron flux between the upper and lower sections of the power range detectors are used to limit the Overtemperature ΔT and Overpower ΔT trip setpoints and to provide the operator with an indication of the core power axial offset. In addition, the output of the power range channels are used for:

1. The rod speed control function
2. To alert the operator to an excessive power unbalance between the quadrants
3. Protect the core against rod ejection accidents
4. Protect the core against adverse power distributions resulting from dropped rods.

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7. The limitations on neutron detector operation and trip setpoints are given in the Technical Specifications.

3.4.5.4 Reactor Vessel Level Instrumentation

The Reactor Vessel Level Instrumentation System (RVLIS) uses differential pressure measuring devices to measure the vessel fluid level or relative void content of the primary coolant. The fluid level or void information is displayed in the main control room for use by the operator as follows:

- Assist in detecting the presence of a gas bubble or void in the Reactor Vessel.
- Assist in detecting the approach of inadequate core cooling.
- Indicate the formation of a void in the RCS

The RVLIS is described in more detail in Section 7.8.4.

References for Section 3.4

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TABLE 3.1-1 (CONT'D)

REACTOR DESIGN PARAMETERS

Thermal and Hydraulic Design Parameters	**Design Value**
Heat Transfer	
Active Heat Transfer, Surface Area, ft^2	48,600
Average Heat Flux, Btu/hr-ft^2	181,400
Maximum Heat Flux for Normal Operation, Btu/hr-ft^2	435,400
Average Thermal Output, kW/ft	5.2
Maximum Thermal Output for Normal Operation, kW/ft	12.5 (1)
Peak linear power for determination of protection set points, kW/ft	22.0 (2)
Heat Flux Hot Channel Factor F(Q)	2.40
Fuel Central Temperature, °F	
Peak at 100% Power	3,580
Peak at Maximum Thermal Output for Maximum Overpower Trip Point	4,150
Core Mechanical Design Parameters	
Fuel Assemblies	
Design	RCC Canless
Number of Fuel Assemblies	157
UO_2 Rods per Assembly	264
Rod Pitch, inches	0.496

TABLE 3.1-1 (CONT'D)

REACTOR DESIGN PARAMETERS

Core Mechanical Design Parameters	Design Value
Fuel Assemblies	
Overall Dimensions, inches	8.426 x 8.426
Fuel Weight (as UO_2), pounds (Cycle 1)	181,205
Zircaloy/ZIRLO™ Weight, lbs.	38,230
Number of Grids per Assembly	9* 2 - non-Mixing Vane 6 - Type R Mixing Vane 1 - Protective Bottom Grid (VANTAGE+ only)
Loading Technique	Multi-Region Non-Uniform
Fuel Rods	
Number	41,448
Outside Diameter, inches	0.374
Diametral Gap, inches (Uncoated pellets)	0.0065
Clad Thickness, inches	0.0225
Clad Material	Zircaloy-4/ZIRLO™
Fuel Pellets	
Material	UO_2 Sintered
Density (% of Theoretical)	95
Diameter, inches, (Uncoated pellets)	0.3225
Solid - Enriched (typical) Length, inches	0.387
Solid - Blanket (typical) Length, inches	0.462
Annular - Blanket (typical) Length, inches	0.462
Diameter of annulus (inches)	0.155

*Includes 1 Inconel top grid, 1 Inconel bottom grid, 6 midgrids and (for VANTAGE+) 1 protective bottom grid.

TABLE 3.4-1 (CONT'D)

REACTOR DESIGN PARAMETERS

Thermal and Hydraulic Design Parameters	17 x 17 With Densification
Average Velocity Along Fuel	
Rods, ft/sec	13.8
Average Mass Velocity, lb/hr-ft^2	2.23 x 10^6
Coolant Temperature	
Nominal Inlet, °F	542.0
Average Rise in Vessel, °F	68.4
Average Rise in Core, °F	72.6
Average in Core, °F	580.2
Average in Vessel, °F	576.2
Heat Transfer	
Active Heat Transfer, Surface Area, ft^2	48,600
Average Heat Flux, Btu/hr-ft^2	181,400
Maximum Heat Flux, for normal operation Btu/hr-ft^2	435,400(2)
Average Thermal Output, kw/ft	5.2
Maximum Thermal Output, for normal operation, kw/ft	12.5(2)
Maximum Thermal Output at Maximum Overpower Trip Point, kw/ft	22.0(4)

SECTION 4

REACTOR COOLANT SYSTEM

LIST OF EFFECTIVE PAGES

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4-2	Revision 8	January, 1990
4-3	Revision 13	January, 1995
4-4	Revision 8	January, 1990
4-5 and 4-6	Revision 18	January, 2000
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4.1-4	Revision 14	January, 1996
4.1-5	Revision 7	January, 1989
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4.1-9	Revision 14	January, 1996
4.1-10	Revision 10	January, 1992
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4.2-26	Revision 17	January, 2000
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4.5-4	Revision 17	January, 1999
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Table 4.5-5 (Deleted)	Revision 8	January, 1990
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SECTION 4

REACTOR COOLANT SYSTEM

The reactor coolant system (RCS), shown in Figure 4.1-1, consists of three similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a reactor coolant pump, two isolation valves, and a steam generator. The system also includes a pressurizer, connecting piping, pressurizer safety and relief valves, and pressurizer relief tank, which are necessary for operational control. Instrumentation which is shown on the flow diagram and is part of the RCS, is discussed in Section 7.

4.1 DESIGN BASES

4.1.1 Performance Objectives

The principal design data of the RCS are given in Table 4.1-1.

The RCS transfers the heat generated in the core to the steam generators where steam is generated to drive the turbine generator.

The RCS provides a boundary for containing the coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits to acceptable values uncontrolled release to the secondary system and to other parts of the unit under conditions of either normal or abnormal reactor behavior. During transient operation the system's heat capacity attenuates thermal transients generated by the core or steam generators. The RCS accommodates coolant volume changes within the protection system limits of the reactor as presented in Section 7.

By appropriate selection of the inertia of the reactor coolant pumps, the thermal-hydraulic effects are reduced to a safe level during the pump coastdown which would result from a loss-of-flow situation. The layout of the system ensures that there is natural circulation capability following a loss-of-flow so as to permit decay heat removal without overheating the core. Part of the systems piping serves as part of the emergency core cooling system (ECCS) to deliver cooling water to the core during a loss-of-coolant accident (LOCA).

4.1.2 Design Criteria

Design criteria which apply to the RCS are given below.

Quality Standards

Those systems and components of the unit which are essential to the prevention, or the mitigation of the consequences, of nuclear

accidents which could cause undue risk to the health and safety of the public are identified and designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they are identified. Where adherence to such codes or standards does not suffice to ensure a quality product in keeping with the safety function, they are supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria are identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria is provided. Where such items are not covered by applicable codes and standards, a showing of adequacy is provided.

The RCS is of primary importance with respect to its safety function in protecting the health and safety of the public.

Quality standards of material selection, design, fabrication and inspection conform to the applicable provisions of recognized codes and good nuclear practice (Section 4.1.6). Details of the quality assurance programs, test procedures and inspection acceptance levels are given in Section 4.3 and 4.5. Emphasis is placed on ensuring the quality of the reactor vessel to obtain material whose properties are uniformly within tolerances appropriate to the application of the design methods of the code delineated in Section 4.1.6.

Performance Standards

Those systems and components of the unit which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public are designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established reflects:

1. Appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area.

2. An appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

RCS piping and components containing operating pressure, and supporting structures thereto are designed as Seismic Category I. Details are given in Section 4.1.3.

The RCS is located in the containment structure whose design, in addition to being a Seismic Category I structure, also considers accidents or other applicable natural phenomena. Details of the containment design are given in Section 5.

Code records are maintained by Westinghouse or their vendors for the mandatory period, and thereafter either by Westinghouse or the licensee.

Records Requirements

The reactor licensee is responsible for ensuring the maintenance throughout the life of the reactor records of the design, fabrication, and construction of major components of the station essential to avoid undue risk to the health and safety of the public.

Records that should be maintained may or may not be under the physical control of the licensee. The licensee ensures that those records which are important, in that they have sole bearing on the health and safety of the public, are maintained.

Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary is designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime.

The RCS in conjunction with its control and protective provisions is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation or anticipated system interactions and maintain the stresses within applicable code stress limits.

Fabrication of the components which constitute the pressure retaining boundary of the RCS is carried out in strict accordance with the applicable codes. In addition there are areas where equipment specifications for RCS components go beyond the applicable codes. Details are given in Section 4.5.

The construction materials of the pressure retaining boundary of the RCS are protected by control of coolant chemistry from corrosion phenomena which might otherwise reduce the system structural integrity during its service lifetime, as discussed in Section 9.1.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions so that continued safe operation is possible, as discussed in Section 7.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code.

Sections of the system which can be isolated are provided with overpressure relieving devices discharging to closed systems such that the system code allowable relief pressure within the protected section is not exceeded.

Monitoring Reactor Coolant Leakage

Means are provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary.

Positive indications in the main control room of leakage of coolant from the RCS to the containment are provided by equipment which permits continuous monitoring of containment air activity and humidity, and runoff from the condensate collecting pans under the cooling coils of the containment air recirculation stations. This equipment provides indication of normal background which is indicative of a basic level of leakage from primary systems and components. Any increase in the observed parameters is an indication of change within the containment, and the equipment provided is capable of monitoring this change. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, containment air recirculation coolers heat load, condensate runoff and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

Further details are supplied in Section 4.2.7.

Reactor Coolant Pressure Boundary Capability

The reactor coolant pressure boundary is capable of accommodating, without rupture, the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release is taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition.

The reactor coolant boundary is shown to be capable of accommodating, without further rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. Details of this analysis are provided in Section 14.

The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are used only to control load variations and core depletion is followed with boron dilution, only the rod cluster control

assemblies (RCCA) in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. Rod insertion limit monitors are provided as an administrative aid to the operator to ensure that this condition is met.

By using the flexibility in the selection of control rod groupings, radial locations and positions as a function of load, the design limits the maximum fuel temperature associated with highest worth ejected rod to a value which precludes any resultant damage to the RCS pressure boundary, i.e., gross fuel dispersion in the coolant and possible excessive pressure surges.

The failure of a rod mechanism housing causing a rod cluster to be rapidly ejected from the core is evaluated as a theoretical, though not credible accident. While limited fuel damage could result from this hypothetical event, the fission products are confined to the RCS and the containment structure. The environmental consequences of rod ejection are less severe than from the hypothetical loss of coolant, for which public health and safety are shown to be adequately protected. Reference is made to Section 14.

Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention

The reactor coolant pressure boundary is designed and operated to reduce to an acceptable level the probability of a rapidly propagating type failure. Consideration is given to the following:

1. Provisions for control over service temperature and irradiation effects which may require operational restrictions

2. Design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation

3. Design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

The reactor vessel design bases are as follows:

1. PROTECTION AGAINST NON-DUCTILE FAILURE: Assurance of adequate fracture toughness in the reactor vessel material is provided by compliance with the requirements for fracture toughness testing set forth in the 1980 issue of the ASME Pressure Vessel and Boiler Code, Section III. In cases where it is not possible to perform all tests in accordance with these requirements, conservative estimates of material fracture toughness are made using information available.

Assurance that the fracture toughness properties remain adequate throughout the service life of the unit is provided by a radiation surveillance program conforming to NRC requirements and ASTM E-185-82, "Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

Safe operating, heatup, and cooldown limits are established according to the 1980 issue of ASME Section III, Appendix G 2000, "Protection Against Non-Ductile Failure."

Changes in fracture toughness of the core region plates, forgings, or weldments in heat affected zones subject to radiation damage will be monitored by a surveillance program which conforms with ASTM E-185-82. The evaluation of the radiation damage in this surveillance program is based on pre-irradiation testing by Charpy V-notch, dropweight test, and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and wedge opening loading specimens carried out during the lifetime of the reactor vessel. Specimens are irradiated in capsules located near the core midheight and are removed from the vessel at specified intervals.

2. CODES AND SPECIFICATIONS: Design and fabrication of the reactor vessel is carried out in strict accordance with ASME Section III.

3. DESIGN TRANSIENTS: Cyclic loads are introduced by normal power changes, reactor trip, startup and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected unit life. Vessel analyses result in a usage factor that is less than 1.

   With regard to the thermal and pressure transients involved in the LOCA, the reactor vessel is analyzed to confirm that the delivery of cold emergency core cooling water to the vessel following a LOCA does not cause a loss of integrity of the vessel.

   The design specifications require analysis to prove that the vessel is in compliance with the fatigue limits of Section III of the ASME Boiler and Pressure Vessel Code. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The heating and cooling rate limits are as described in the Technical Specifications. These rates are reflected in the vessel design specifications.

4. INSPECTION: The internal surface of the reactor vessel is capable of inspection periodically using visual and/or nondestructive techniques over the accessible areas. During refueling, the vessel cladding is capable of being inspected in certain areas between the closure flange and the primary coolant inlet nozzles, and if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

   The closure head is examined visually during each refueling. Optical devices permit a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. The knuckle transition piece, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, dye penetrant or magnetic particle, and ultrasonic testing. The closure studs can be inspected periodically using visual, magnetic particle, and/or ultrasonic techniques.

All pressure containing components of the RCS are designed, fabricated, inspected, and tested in conformance with the applicable codes. Further details are given in Section 4.1.6 and 4.5.

Reactor Coolant Pressure Boundary Surveillance

Reactor coolant pressure boundary components have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes is provided.

The design of the reactor vessel and its arrangement in the system provides the capability for accessibility during service life to the entire internal surfaces of the vessel and certain external zones of the vessel including the nozzle to reactor coolant piping welds and the top and bottom heads. The reactor arrangement within the containment provides sufficient space for inspection of the external surface of the reactor coolant piping, except for the area of pipe passing through the primary shielding concrete. Further details are given in Section 4.5.

4.1.3 Design Characteristics

Design data for the respective RCS components are listed in Tables 4.1-3 through 4.1-8 and Table 4.1-12.

Design Pressure

The RCS design and operating pressures together with the safety, power relief and pressurizer spray valves setpoints, and the protective system setpoint pressures are listed in Table 4.1-2. The selected design margin includes operating transient pressure changes

from core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics. Table 4.1-9 gives the design pressure drop of the RCS components. Relief valves are shown on Figure 4.1-1. Boundaries with the ECCS and auxiliary systems are discussed in Sections 6 and 9.

Design Temperature

The design temperature for each component is selected to be above the maximum coolant temperature in that component under all normal and anticipated transient load conditions. The design and operating temperatures of the respective system components are listed in Tables 4.1-3 through 4.1-8 and 4.1-12.

Seismic Loads

The seismic loading conditions are established by the Operating Basis Earthquake (OBE) and Design Basis Earthquake (DBE). The former is selected to be typical of the largest probable ground motion based on the site seismic history. The latter is selected to be the largest potential ground motion at the site based on seismic and geological factors and their uncertainties. Refer to Section 2.5.

For the OBE loading condition, the RCS 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 remain operable. The seismic design for the DBE is intended to provide a margin in design that ensures capability to shut down and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that the RCS 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 "no-loss-of-function" loading condition.

The criteria adopted for seismic analyses for equipment are defined in Appendix B.

Design and construction practices in accordance with these criteria ensure the integrity of the RCS under seismic loading.

An integrated dynamic analysis of the reactor coolant piping, the NSSS equipment and NSSS equipment supports has been performed.

The integrated system was analyzed for both seismic and pipe rupture conditions. For the seismic analysis, building response spectra at building support interfaces were used as input. For the rupture condition, breaks at various critical locations in the secondary piping were considered. Time history forcing functions associated with the various breaks were used as input to the integrated dynamic model.

to a heatup or cooldown rate under abnormal or emergency conditions. The heatup occurs from ambient to the no load temperature and pressure condition and the cooldown represents the reverse situation. In actual practice, the rate of temperature change of 100°F per hr will not be usually attained because of other limitations such as:

a. Criteria for prevention of non-ductile failure which establish maximum permissible temperature rates of change, as a function of plant pressure and temperature.

b. Slower initial heatup rates when using pumping energy only.

c. Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, rod withdrawal, sampling water chemistry and gas adjustments.

The heating and cooling rate limits are as described in the Technical Specifications. Ideally, heatup and cooldown would occur only before and after refueling. In practice, additional unscheduled unit cooldowns may be necessary for plant maintenance. The frequency of maintenance shutdowns is expected to decrease as the unit matures.

2. UNIT LOADING AND UNLOADING: The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5 percent per minute between 15 percent load and full load. This load swing is the maximum possible consistent with operation with automatic reactor control. The reactor coolant temperature varies with load as prescribed by the temperature control system.

3. STEP INCREASE AND DECREASE OF 10 PERCENT: The ±10 percent step change in load demand is a control transient which is assumed to be a change in turbine control valve opening which might be occasioned by disturbances in the electrical network into which the unit output is tied. The reactor control system is designed to restore unit equilibrium without reactor trip following a ±10 percent step change in turbine load demand initiated from unit equilibrium conditions in the range between 15 percent and 100 percent full load, the power range for automatic reactor control. In effect, during load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized, and reactor coolant temperature is restored to its programmed

setpoint at a sufficiently slow rate to prevent excessive pressurizer pressure decrease.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same increment of time, the RCS average temperature and pressurizer pressure also initially increase. Because of the power mismatch between the turbine and reactor and the increase in reactor coolant temperature, the control system automatically inserts the control rods to reduce core power. With load decrease, the reactor coolant temperature is ultimately reduced from its peak value to a value below its initial equilibrium value at the inception of the transient. The reactor coolant average temperature setpoint change is made as a function of turbine-generator load as determined by first stage turbine pressure measurement. The pressurizer pressure is also decreased from its peak pressure value and follows the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash which reduces the rate of pressure decrease. Subsequently the pressurizer heaters come on to restore the reactor pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs, i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters and eventually the system pressure is restored to its normal value.

The reactor coolant average temperature is raised to a value above its initial equilibrium value at the beginning of the transient.

4. LARGE STEP DECREASE IN LOAD: This transient applies to a step decrease in turbine load from full power of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature automatically initiates a secondary side steam dump system that avoids a reactor shutdown or lifting of steam generator safety valves. Thus, when a unit is designed to accept a step decrease of 95 percent from full power, it signifies that a steam dump system is capable of providing a heat sink to accept 85 percent of the turbine load. The remaining 10 percent of the total step change is assumed by the reactor rod control system as noted in Section 3. If a steam dump

100°F per hr maximum rate.

2. HYDROSTATIC TEST CONDITIONS: The pressure tests are outlined below:

   a. Primary Side Hydrostatic Test Before Initial Startup - The pressure tests covered by this section included both shop and field hydrostatic tests which occurred as a result of component or system testing. This hydrostatic test was performed using a separate hydro test pump prior to initial fuel loading at a water temperature which was compatible with the reactor vessel material design transition temperature requirements and a maximum test pressure of 3,107 psig or 1.25 times the design pressure. In this test, the primary side of the steam generator was pressurized to 3,107 psig coincident with the secondary side pressure of 0 psig.

   b. Secondary Side Hydrostatic Test Before Initial Startup - The secondary side of the steam generator was pressurized to 1.25 times the design pressure of the secondary side coincident with the primary side at 0 psig.

   c. Primary Side Leak Test - Subsequent to each time the primary system has been opened, a leak test is performed. During this test, the primary system pressure is for design purposes, assumed to be raised to 2500 psia, with the system temperature above the design transition temperature, while the system is checked for leaks.

      In actual practice, the primary system will be pressurized to less than 2500 psia to prevent the pressurizer safety valves from lifting during the leak test.

      During this leak test, the secondary side of the steam generator will be pressurized so that the pressure differential across the tubesheet does not exceed 1600 psi. This is accomplished by closing off the steam lines.

Since the tests outlined under item a. and b. occur prior to unit startup, the number of cycles is independent of unit life.

The system hydrostatic test at 1.25 times design pressure, the post-operational hydrostatic tests at 2485 psig, and the post-operational leak tests at 2235 psig shall be made at temperatures not lower than the Reference Temperature Nil-Ductility Temperature, RT(NDT) + 60°F. The limiting RT(NDT) was determined in accordance with calculation methods described in Reference 4. The limiting RT(NDT) will increase with fast neutron

exposure. Thus, prior to each leak test, the RT(NDT) will be adjusted in accordance with the fluence curve or actual data obtained from the reactor vessel surveillance program.

The BVPS-1 reactor vessel was ordered and designed to the ASME Boiler and Pressure Vessel Code, Section III, 1968 Edition. No provisions have been made to update the vessel to the new criteria of the 1972 Summer Addenda.

4.1.5 Service Life

The service life of the RCS pressure containing components depends upon the end-of-life material radiation damage, operational thermal cycles, design and manufacturing quality standards, environmental protection, maintenance standards, and adherence to established operating procedures.

The reactor vessel is the only component of the RCS which is exposed to a significant level of neutron irradiation and it is, therefore, the only component which is subject to material radiation damage effects.

The RT(NDT) shift of the vessel material and welds due to radiation damage effects during service is monitored by a radiation damage surveillance program. Details are given in Section 4.5.

Reactor vessel design is based on the transition temperature method of evaluating the possibility of brittle fracture of the vessel material as a result of operation.

To establish the service life of the RCS components as required by Section III of the ASME Boiler and Pressure Vessel Code for Class A vessels, the operating conditions are established for the 40 yr design life. These operating conditions include the cyclic application of pressure loadings and thermal transients.

The number of thermal and loading cycles used for design purposes is listed in Table 4.1-10.

Environmental protection is afforded by close adherence to the water chemistry limits set forth in the Technical Specifications and by the absence of any deleterious conditions in the containment environment, and by pipe and component insulation.

Maintenance standards comply with the applicable codes and standards and with appropriate quality levels. Operating procedures are established and adhered to in accordance with the Beaver Valley Quality Assurance Program.

4.1.6 Codes and Classifications

All primary pressure-containing components of the RCS are designed, fabricated, inspected, and tested in conformance with

4.2 SYSTEM DESIGN AND OPERATION

4.2.1 General Description

The RCS consists of three similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, two isolation valves, loop piping and instrumentation. The pressurizer surge line is connected to the hot leg of one of the loops. Auxiliary system piping connections into the reactor coolant piping are provided as necessary. A flow diagram of the system is shown in Figure 4.1-1.

RCS design data are listed in Tables 4.1-1 through 4.1-8 and Table 4.1-12.

Pressure in the system is controlled by the pressurizer, through the use of electrical heaters and sprays. Steam can either be formed by the heaters, or condensed by a pressurizer spray to minimize pressure variations due to contraction and expansion of the coolant. Instrumentation used in the pressure control system is described in Section 7. Spring-loaded steam safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water.

4.2.2 Components Description

4.2.2.1 Reactor Vessel

The reactor vessel is manufactured by Combustion Engineering, Inc. It is cylindrical with a welded hemispherical bottom head and a removable bolted, flanged and gasketed hemispherical upper head. The reactor vessel flange and head are sealed by two hollow metallic O-rings. Seal leakage may be detected by means of two leakoff communications, one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The reactor vessel closure head contains head adaptors. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contain acme threads for the assembly of control rod drive mechanisms or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. Inlet and outlet nozzles are spaced evenly around the vessel. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of Inconel. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel which are in contact with primary coolant are weld overlay with 0.125 inches minimum of stainless steel. The exterior of the reactor vessel is insulated with canned stainless steel reflective sheets. The insulation is 3 inches thick and contoured to enclose the top, sides, and bottom of the vessel. Access to vessel side insulation is limited by the neutron shield tank.

A one-piece thermal shield, concentric with the reactor core, is located between the core barrel and the reactor vessel. The top of the shield is bolted to the core barrel. The shield, which is cooled by the coolant on its downward pass, protects the vessel by attenuating much of the gamma radiation and some of the fast neutrons which escape from the core. This shield reduces thermal stresses in the vessel which result from heat generated by the absorption of gamma energy. The shield is described in Section 3.2.3.1.

Surveillance specimens made from reactor vessel steel are located between the reactor vessel wall and the thermal shield. These specimens will be examined at selected intervals to evaluate reactor vessel material RT(NDT) changes as described in Section 4.5.1.

The reactor vessel internals are designed to direct the coolant flow, support the reactor core, and guide the control rods in the withdrawn position. The reactor vessel contains the core support assembly, upper internals assembly, fuel assemblies, control cluster assemblies, surveillance specimens, and incore instrumentation.

A schematic of the reactor vessel is shown in Figure 4.2-1. The materials of construction are given in Tables 1.8-1 and 1.8-3 and the design parameters are given in Table 4.1-3. A description of the reactor vessel internals is given in Section 3.2.3.1.

4.2.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with essentially hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. The surge line nozzle and removable electric heaters are installed in the bottom head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevent a cold insurge of water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzles, relief and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray

Principal design data for the reactor coolant piping are given in Table 4.1-7.

4.2.2.7 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 that are 3 inches and larger, 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 RCS valve leakoff connections within the containment are piped to a header which can discharge to either the pressurizer relief tank (PRT) or No. 1 primary drains tank (PDT). Leakage to the containment is essentially zero for these valves. Reactor coolant chemistry parameters are specified to minimize corrosion. Periodic analyses of coolant chemical composition ensures that the reactor coolant meets these specifications. The upper-limit coolant velocity of about 50 ft per sec precludes accelerated corrosion.

Valve leakage is minimized by design features as discussed above.

Pressurizer Safety Valves

The pressurizer safety valves are pilot operated valves consisting of two principle assemblies - a pilot and main valve. These two assemblies are coupled to provide a unitized, self actuated safety valve to prevent system pressure from exceeding the design pressure by more than 110 percent, in accordance with the ASME Boiler and Pressure vessel Code, Section III. The set pressure of the valves is 2,485 psig.

A water seal is maintained below each safety valve seat to minimize leakage. The 6 inch pipes connecting the pressurizer nozzles to their respective code safety valves, are shaped in the form of a loop seal. Condensate, as a result of normal heat losses to the ambient, accumulates in the loop seal, thus flooding the valve seat. The water prevents any leakage of hydrogen gas or steam through the safety valve seats. This condensate temperature is held to 300°F minimum. This is accomplished by use of an insulated enclosure around the loop piping up to and including the valve inlet flange. The enclosure is attached to the pressurizer insulation with a portion of this insulation removed within the enclosure boundary. Heat from the pressurizer is held within the enclosure thus helping to maintain the loop seal temperature within the limits of 300 to 400°F. With the loop seal so heated, the piping support reactions are minimized due to flashing of the seal water upon activation of the safety relief valves.[5] If the pressurizer pressure exceeds the set pressure of the safety valves, they will start lifting, and the water from the seal will discharge during the accumulation period. Pressure switches on

the safety valves and a temperature indicator in the safety valve discharge manifolds alert the operator to the passage of steam due to leakage or valves lifting. These pressure switches monitor the pilot valve chamber for leakage which could lift the safety valve below setpoint.

The pressurizer safety valve support is designed to withstand seismic, thermal, and dead weight forces in addition to the valve discharge reactions. The supports consist of:

1. Two circumferential anchor straps placed around the pressurizer vessel, and held in place by the forces of pressure and friction

2. Two built-up box sections which are welded to each other and are bolted to the straps

3. A flange welded to the box sections and bolted to the safety valve flange.

Power Relief Valves

The pressurizer is equipped with power-operated relief valves which limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the power-operated relief valves if excessive leakage occurs.

Three Power-Operated Relief Valves (PORVs) are installed on the pressurizer as shown on Figure 4.1-1. The PORVs are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percent step load decrease with steam dump but without reactor trip. Manual operator control of the PORVs may also be used as a recovery action to depressurize the RCS following a steam generator tube rupture event. The PORVs are spring loaded to close and require air to open. Air to the PORV actuators is normally supplied by the containment instrument air system; however, each of the three PORVs is also provided with a nitrogen backup supply to the normal containment instrument air system. A nitrogen backup supply is provided for each of the three PORVs in Modes 1-3. The backup nitrogen trains are seismically designed and supported and include a separate accumulator for each PORV. Nitrogen to the three accumulators is provided by the same source used to supply nitrogen to the safety injection accumulators.

Two of the three installed PORVs (PCV-RC-455C and PCV-RC-455D) are also used as part of the Overpressure Protection System (OPPS). The OPPS protects the RCS from pressure transients at low temperatures by preventing any pressure transient from exceeding 10 CFR 50 Appendix G limits.

These two PORVs have a low pressure setpoint which is operational when the Reactor Coolant System decreases below the OPPS enabling temperature defined by the Plant Technical Specifications. As described in Section 4.2.3, the design basis for the low pressure setpoint is to limit RCS overpressurization resulting from either mass input or heat input transients to the RCS. The design basis for OPPS assumes no operator action for the first ten minutes following the initiating event.

Design parameters for the pressurizer spray control, safety, and power relief valves are given in Table 4.1-8.

Valve Operability Tests

Full size proof tests to show that the pressurizer safety and relief valves and block valves would perform their intended function were performed. See Reference 6 for details.

Loop Stop Valves

The reactor coolant loop stop valves shown in Figure 4.2-9 are remotely controlled motor operated gate valves which permit any loop to be isolated from the reactor vessel. One valve is installed on each hot leg and one on each cold leg. Coolant is circulated in an isolated loop through a bypass line, which contains a remotely controlled motor-operated stop valve. This bypass valve is closed during normal loop operation. To protect the reactor coolant pump, a valve-pump interlock circuit prevents the starting of the reactor coolant pump in a given loop unless the cold leg (discharge) valve is closed and the bypass valve is open. The interlock also prevents pump operation if the bypass valve and either of the stop valves are closed.

Note that Tech Spec Amendment 195 revised the method for isolated loop startup; therefore, the interlock system for opening a cold leg loop stop valve, as described below, can be procedurally bypassed.

To ensure against an accidental startup of an unborated and/or cold isolated loop, an additional valve interlock system is provided which meets IEEE 279-1971. The additional interlocks are for the purpose of ensuring flow from the isolated loop to the remainder of the RCS takes place through the relief line stop valve (after system pressure is equalized through the loop drain header and the hot leg stop valve is opened) for a period of approximately 90 min. before the cold leg loop stop valve is opened.

The flow through the relief line is low (approximately 200 to 300 gpm) so that the temperature and boron concentration are brought to equilibrium with the remainder of the system at a relatively slow rate. The valve-temperature relief line flow interlock:

1. Prevents opening of a hot leg stop valve unless the cold leg loop stop valve is closed.

2. Prevents starting a reactor coolant pump unless:

   a. The cold leg loop stop valve is closed or

   b. Both the hot leg loop stop valve and cold leg loop stop valve are open.

3. Prevents opening of a cold leg loop stop valve unless:

   a. The hot leg loop stop valve has been opened a specified time.

   b. The loop bypass valve has been opened a specified time.

   c. Flow has existed through the relief line for a specified time.

   d. The cold leg temperature is within 20°F of the highest cold leg temperature in other loops, and the hot leg temperature is within 20°F of the highest hot leg temperature in the other loops.

The parameters of each reactor coolant loop stop valve are shown in Table 4.1-12.

4.2.2.8 RCS Supports

The supports for the major components in the RCS are described in Section 5.2.

4.2.3 Pressure-Relief

Pressure-Relieving Devices

The RCS is protected against overpressure by protective circuits such as the high pressure trip and by relief 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 valve design parameters are given in Table 4.1-8. The valves are further discussed in Section 4.2.2.7.

Overpressure Protection System (OPPS)

The OPPS consists of two separate trains each containing a PORV and associated actuation circuitry. Additionally, the two PORVs (PCV-RC-455C and PCV-RC-455D) used by the OPPS each have a separate backup nitrogen supply that is seismically designed and supported. Each nitrogen supply train includes a nitrogen accumulator. Each accumulator is sized to permit ten minutes of PORV actuation following a low temperature overpressure transient (LTOP) without any operator action. For OPPS operation the

nitrogen accumulators are typically charged to a pressure of approximately 675 psig. The OPPS design includes a pressure switch on each train that initiates an alarm in the control room when a nitrogen accumulator pressure falls below 600 psig.

The OPPS is designed to operate assuming the limiting single failure in the OPPS in addition to the failure mechanism that initiated the RCS overpressurization transient. Except for the case where a loss of power from station battery #2 occurs with a charging pump in service, the OPPS satisfies the single failure criteria. Since a loss of station battery 2 results in both isolation of the letdown line and loss of power to one PORV, an assumed single failure in the other OPPS PORV train would cause the entire OPPS to be unavailable. To address this scenario, a dedicated operator is provided to the benchboard whenever the RCS is in a water solid condition with a charging pump in service.

At low system temperatures, the allowable system pressure is significantly less than the design pressure of 2485 psig, necessitating additional means to alleviate concerns associated with brittle fracture of the reactor vessel. The enable temperature for the OPPS is given in the Technical Specifications. Therefore, overpressure mitigation provisions for the reactor vessel, as provided by the OPPS, must be available when the RCS and the reactor vessel are at temperatures less than the enable temperature.

During a normal plant heatup, the RCS is open to the Residual Heat Removal System (RHRS) and may be operated for a short period of time in a water solid mode until a steam bubble is formed in the pressurizer. The RHRS is provided with a self-actuated water relief valve to prevent overpressure caused either within the system itself or from transients transmitted from the RCS. During these low-temperature, low-pressure operating conditions, the OPPS is armed and in a ready status to mitigate pressure transients. In determining the OPPS setpoints, no credit is taken for RHR relief valve operation. When the reactor coolant temperature has increased above the enable temperature, the OPPS is manually disarmed.

During a normal plant cooldown, the OPPS is manually armed as the reactor coolant temperature is decreased below the enable temperature. Note that at this time there is a steam bubble in the pressurizer and the water level is at the normal level for no-load operation. The RHRS is normally placed in service by opening the suction isolation valves prior to the OPPS being placed in service. When the coolant temperature has decreased to about 160°F, the steam bubble may be collapsed and the reactor coolant pumps stopped. The steam bubble may be collapsed with one RCP running to a water solid condition during Mode 5 only. In addition, the steam bubble may be formed with one RCP running from a water solid condition through steam bubble formation. Restrictions of running the RCP water solid are proceduralized. From this point on in the cooldown, the OPPS will be in an active status ready to mitigate pressure transients which might occur.

Potential overpressurization transients to the RCS can be caused by either of two types of events to the RCS, mass input or heat input. Both types result in more rapid pressure changes when the RCS is water solid. Specifically, the OPPS design bases transients are defined as: 1) the mass input transient caused by a normal charging/letdown flow mismatch after the termination of letdown flow and 2) the heat input transient caused by the restart of a Reactor Coolant Pump (RCP) when a temperature asymmetry exists within the RCS due to the continued injection of cold seal injection water.

For a particular mass input transient to the RCS, the relief valve will be signaled to open at a specific pressure setpoint. However, there will be a pressure overshoot during the delay time before the valve starts to move and during the time the valve is moving to the full open position. This overshoot is dependent on the dynamics of the system and the input parameters, and results in a maximum system pressure somewhat higher than the set pressure. Similarly, there will be a pressure undershoot, while the valve is relieving, both due to the reset pressure being below the setpoint and to the delay in stroking the valve closed. The maximum and minimum pressures reached in the transient are a function of the selected setpoint and must fall within the acceptable pressure range. Note that the pressure overshoot and undershoot for the mass input case is greatest at low temperatures. Thus, the overshoot calculation is limited to the most restrictive low temperature condition only. Whereas, the heat input evaluation calculates the pressure overshoot for a range of reactor coolant temperatures.

The range of allowable setpoints for the OPPS is determined by superimposing the results of the several mass input and heat input cases evaluated and selecting setpoints that will satisfy both types of transients. The selection of the pressure setpoint for the PORVs is based on the use of nominal upper and lower limits.[7] The OPPS is considered to be a mitigation system, as opposed to a protection system, and the use of nominal limits is understood and approved by the NRC. The steady-state pressure-temperature limit is used as the basis for setpoint selection to provide the greatest operational flexibility. This limit has been accepted by the NRC with the justification that "most transients occur during isothermal metal conditions."

The development of the reactor coolant system heatup and cooldown curves is accomplished by following the guidance provided by Regulatory Guide 1.99, Revision 2. These curves represent operational limitations to be followed during heatup or cooldown transitions and are not utilized by themselves for determining the OPPS setpoint since they do not represent steady-state pressure-temperature conditions.

The techniques used to measure and predict the integrated fast neutron (E > 1 Mev) fluxes at the sample locations are described in Appendix 4A. The calculation method used to obtain the maximum neutron (E > 1 Mev) exposure of the reactor vessel is identical to that described for the irradiation samples. Since the neutron spectrum at the sample can be applied with confidence to the adjacent section of reactor vessel, the vessel exposure is obtained from the measured sample exposure by appropriate application of the calculated azimuthal neutron flux variation.

The original maximum integrated fast neutron (E > 1 Mev) exposure of the vessel was computed to be 2.59×10^{19} n per cm^2 at 1/4 thickness for 40 yr. operation at 2,660 MWt at 80 percent load factor.

The predicted RT(NDT) temperature shift for an integrated fast neutron (E > 1 Mev) exposure of 2.59×10^{19} n per cm^2 was 202°F, the value obtained from the curve shown in Figure 4.2-8 for irradiation (0.20 percent Cu).

To evaluate the RT(NDT) temperature shift of welds, heat affected zones, and base material for the vessel, test coupons of these materials types have been included in the reactor vessel surveillance program described in Section 4.5.

The methods used to measure the initial RT(NDT) temperature of the reactor vessel base plate material are given in Appendix 4A.

4.2.6 Maximum Heating and Cooling Rates

The RCS operating cycles used for design purposes are given in Table 4.1-10 and described in Section 4.1.5. The heating and cooling rate limits are as described in the Technical Specifications. Sufficient electrical heaters are installed in the pressurizer to permit a heatup rate of 55°F per hr, starting with a minimum water level. This rate takes into account the small continuous spray flow provided to maintain the pressurizer liquid homogenous with the coolant.

The fastest cooldown rates which result from the hypothetical case of a break of a main steam line are discussed in Section 14.

4.2.7 Leakage

4.2.7.1 Leakage Detection

Coolant leakage from the RCS to the containment is indicated in the main control room by one or more of the following methods:

1. The containment air recirculation fan coolers normally maintain the containment atmosphere at its design operating temperature and humidity. Leakage from the RCS will increase the heat load on the coolers. A 5 gpm leak from the RCS will increase this heat load about 20 percent. The outlet temperature of cooling water for the containment air recirculation fan is indicated in the control room.

2. Containment gas and particulate radiation monitors. Experience has shown that these monitors, which are described in Section 11.3.4, respond rapidly to reactor coolant leakage and provide a sensitive indication of such leakage. The time required to detect reactor coolant leakage depends on the size of the leak, reactor coolant activity level, and containment background activity due to prior leakage. The following cases illustrate this:

   a. CASE 1: If there is no prior reactor coolant leakage into the containment and there is 1 percent failed fuel, a 0.1 gpm reactor coolant leak can be detected in approximately one minute as shown in Figure 4.2-10. The particulate monitor is more sensitive than the gas monitor to small leaks, while the gas monitor has a faster response for leak rates greater than 0.7 gpm.

   b. CASE 2: If there is no prior reactor coolant leakage into the containment and the reactor coolant gaseous activity is 0.6 mCi/cc (typical of operating PWR's) a 100 gpm leak can be detected in less than one minute but it will take 1.3 hr to detect a 1 gpm leak.

   c. CASE 3: If there is prior continuing leakage of 0.5 gpm into the containment and the containment gas monitor high radiation alarm setting is twice the existing steady state containment activity, it will take about 340 hr to detect a 1 gpm leak. In this case, the time to detect leakage is not a function of coolant activity level (assumed constant), but rather is a function of leak rate.

3. Any leakage causes an increase in the amount of makeup water required to maintain normal level in the pressurizer and/or volume control tank. The primary grade water and concentrated boric acid makeup flow rate are both recorded and alarmed in the main control room.

4. Containment sump water level. Leakage causes the containment sump water level to increase. The containment sump level is also indicated and alarmed in the main control room.

5. Containment pressure, temperature, and humidity instrumentation. Leakage causes the containment pressure, temperature, and humidity to increase. The containment pressure, temperature, and humidity are indicated in the main control room and recorded in the data logger. The containment pressure is also alarmed in the main control room.

6. Reactor vessel flange leakage is collected in the primary drains tank (PDT) and indicated by high temperature in the flange leakoff line (alarm in the main control room). Leakage from this pathway is monitored by the alarm function which annunciates if the temperature detector in the head flange leakoff line reaches a predetermined temperature. Leakage from this pathway is accounted for since this leakage is collected in the PDT which is included in the RCS water inventory balance determinations.

Method two can only be used for leakage detection if there is sufficient radioactivity in the reactor coolant. If there are not such activated products in the reactor coolant, the other methods can be used to detect a leak.

Leakage from unidentified sources will pass to the containment structure in the liquid and vapor phase and will be collected in the containment sump. The containment structure has areas that may temporarily hold up small amounts of liquid and thus prevent the liquid from immediately reaching the containment sump. In addition, the containment sump also collects liquid from sources other than the reactor coolant boundary. The determination of exact reactor coolant pressure boundary leakage, accurate to 1 gpm, within 4 hours, by measuring collected water in the containment sump, is reliable. A response time of 4 hours is consistent with the guidance of NRC Generic Letter 84-04. Therefore, the system meets the sensitivity requirements of Regulatory Guide 1.45.

Intersystem leakage, such as leakage from the reactor coolant system can be detected by continuous radiation monitors, described in Sections 11.3.3.3.13, 14, and the Technical Specifications. Intersystem leakage from the reactor coolant system to the component cooling water system can be detected by a continuous radiation monitor described in Section 11.3.3.3.10.

The leakage detection system is capable of detecting a 1 gpm leak in 4 hours under all conditions. This is to ensure that the RCS Primary loop piping leakage will be detected and action taken prior to a flaw reaching critical size and causing a pipe rupture. Reference 4 discusses critical cracks in the piping system. This reference shows that, for lines 3 inches or more in diameter, leakage through a critical through-wall crack is considerably greater than the minimum detectable leak. This report also notes that for pipes greater than 4 inches in diameter a .crack capable of leaking at 5 gpm is considerably smaller than a critical crack. Therefore, catastrophic failure of the piping system is not expected for this 5 gpm leak. For lines 4 inches and smaller, core cooling analysis shows that breaks of this equivalent cross-sectional area will not result in reactor fuel clad damage; therefore, the sensitivity of 1 gpm under all conditions is justified.

4.2.7.2 Leakage Prevention

RCS components are manufactured to exacting specifications which exceed normal code requirements as outlined in Section 4.1.6. Leakage through metal surfaces or welded joints is unlikely because of the welded construction of the RCS and the extensive nondestructive testing to which it is subjected.

Some leakage from the RCS is permitted by the reactor coolant pump seals. Also, all sealed joints are potential sources of leakage even though the most appropriate sealing device is selected in each case. Because of the large number of joints and the difficulty of ensuring complete freedom from leakage in each case, a small integrated leakage is considered acceptable. All valves three (3) inches and larger in lines connecting to the RCS which are normally subjected to RCS operating conditions are provided with leakoff connections. Some of these valves are equipped with backseats which limit leakage.

4.2.7.3 Locating Leaks

Experience has shown that hydrostatic testing is successful in locating leaks in a pressure containing system.

Methods of locating leaks during a unit shutdown include visual observation for escaping steam or water, or of boric acid crystals near the leak. The boric acid crystals are transported outside the RCS in the leaking fluid and deposited by the evaporation process.

4.2.8 Water Chemistry

The water chemistry is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces.

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality listed in Table 4.2-2. Maintenance of the water quality to minimize corrosion is accomplished using the chemical and volume control system and sampling system which are described in Sections 9.1 and 9.6, respectively.

In order to monitor and maintain the secondary water to the specifications given in Table 4.2-3, it is intended that automatic continuous analysis equipment will be provided for the Hotwell, Condensate Pump and Feed Pump sample points.

These inputs monitor reactor internals motion by means of the core-motion-induced reactivity changes.

If any one of the eight loose parts channels exceeds a pre-set impact energy level amplitude, and passes through alarm discrimination logic, an alarm will be indicated in the control room and at the LPMS monitor cabinet located in the process rack area. Alarm discrimination logic is designed to minimize false alarms. LPM System alarms are blocked when the control rods are in motion.

The LPMS provides constant monitoring of loose parts and automatically saves all impact data on computer disk. Frequency trend data is saved several times per day. The LPMS records inputs from the initiating channel and the three other closest channels which may provide supplemental information, according to a pre-programmed selection. The LPMS supplies real time data for reference. Any channel may be audibly monitored at the LPMS cabinet.

The LPMS monitoring system includes a time and frequency domain analyzer and a graphics printer, with which Power Spectral Density (PSD) plots may be made. PSD plots are graphs of amplitude versus frequency. Base line PSD signatures may be made during pre-operational testing. Additional operational PSD signatures will be made during initial operation to provide bases for future comparison.

4.2.11 Reactor Coolant Gas Vent System

The reactor coolant gas vent system provides a means to remotely vent noncondensable gases from the reactor vessel head or the pressurizer steam space. The system is designed in accordance with ASME III. The reactor coolant gas vent system was added as a requirement of an NRC Order[10] in response to NUREG 0737 TMI Issue II.B.1.

The reactor coolant gas vent system is used following an accident which generates significant quantities of noncondensable gases that inhibit core cooling. The need for venting and the approximate volume of gas can be determined for the reactor from the reactor vessel level instrumentation and for the pressurizer from the pressurizer temperature and pressure. The gases may be discharged into the containment dome or the pressurizer relief tank (see Figure 4.1-1). The flow from the system is less than 100 cfm, H_2, depending on temperature and pressure. The venting operation is accomplished from the control room using keyswitches which actuate the normally closed (fail closed) solenoid valves. Position indicating lights on the control board provide a positive indication of each valve position.

Two solenoid valves in parallel are installed in both vessel head vent line and the pressurizer vent line to provide assurance that the required vent path may be established when needed. One solenoid valve is installed on each exhaust line such that each vent path has double isolation. Parallel valves are powered from separate emergency buses such that a vent path is available from the vessel head or pressurizer with the loss of power from either bus.

The potential flow from the reactor coolant system is restricted to less than the make up capacity of one charging pump by a 7/32 inch orifice at the vent line connections to the reactor vessel head and the pressurizer. Inadvertent actuation of both the reactor vessel and the pressurizer vent at the same time is prevented by use of a single key for the four control board keyswitches which control the parallel valves on each vent path. A single key is provided for actuation of either of the two exhaust line solenoid valve control board keyswitches.

Pressure instrumentation in the vent line will detect leakage past the reactor vessel head and pressurizer solenoid isolation valves. During normal plant operation, the vent line pressure is displayed in the control room.

The exhaust line to containment discharges directly into the containment dome, without obstruction so as to provide good mixing of vented gases. The use of the pressurizer relief tank allows removal of small quantities of gas without releasing radioactive fluid/gas into the containment or increasing hydrogen concentration levels. Venting of large quantities of gas to the pressurizer relief tank will rupture the rupture disc providing a second path to containment for vented gas.

The Reactor Coolant Gas Vent System (RCGVS) may be used as an alternate letdown path in the event of an Appendix R design basis fire which is postulated to disable redundant normal letdown controls. One train of RCGVS valves is operable from the Backup Indicating Panel (BIP) in the East Cable Vault (Refer to Chapter 7.8). Keylock isolation switches on the BIP Transfer Panels prevent operation of these valves from the BIP under normal operating conditions.

References for Section 4.2

1. Deleted by Revision 17.

2. Deleted by Revision 17.

3. J. W. Murdock, "Performance Characteristics of Elbow Flowmeteres," Transactions of the ASME, (September 1964).

4. J. J. Szyslowski, R. Salvatori, "Determination of Design Pipe Breaks for Westinghouse Reactor Coolant Systems" WCAP-7503 Revision 1, Westinghouse Electric Corporation (February 1972).

5. Duquesne Light Company to NRC submittal concerning NUREG-0737, Item II.D.1 Pressurizer Safety and Relief Line Piping and Support Evaluation dated June 24, 1983.

6. Duquesne Light Company to NRC submittal concerning NUREG-0737, Item II.D.1 Plant Specific Report, dated July 1, 1982.

7. Beaver Valley Unit 1 Low Temperature Overpressure Protection System (LTOPS) Setpoint Analysis at 16, 24, 32 and 48 EFPY, Westinghouse Letter DLW-90-528, dated January 23, 1990.

8. The term "equivalent" is described in UFSAR Section 1.8.2, "Equivalent Materials."

9. P. L. Strauch, W. H. Bamford, B. A. Bishop, D. Kurek, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," WCAP-14535-A, Westinghouse Electric Corporation (January 1996).

10. S. A. Varga, Jr. (USNRC) BVPS-1 Order Modifying License, letter to J. J. Carey (BVPS) (July 10, 1981).

prevention criteria will impose a lower limit to heatup and cooldown rates.

Before unit cooldown is initiated, the boron concentration in the RCS is increased to the cold shutdown concentration, and the concentration is verified by sampling. Thus, during reactor cooldown, no changes are imposed on the boron concentration.

It is therefore concluded that the temperature changes imposed on the RCS during its normal modes of operation do not cause any abnormal or unacceptable reactivity changes.

The design cycles as discussed in the preceding section are conservatively estimated for equipment design purposes and are not intended to be an accurate representation of actual transients or for all cases reflect operating experience.

Certain design transients, with an associated pressure and temperature curve, have been chosen and assigned an estimated number of design cycles for the purpose of equipment design. These curves represent an envelope of pressure and temperature transients on the RCS boundary with margin in the number of design cycles chosen based on operating experience.

To illustrate this approach, the reactor trip transient can be mentioned. Four hundred design cycles are considered in this transient. One cycle of this transient would represent any operational occurrence which would result in a reactor trip. Thus, the reactor trip transient represents an envelope design approach to various operational occurrences.

This approach provides a basis for fatigue evaluation to ensure the necessary high degree of integrity for the RCS components.

System hydraulic and thermal design parameters are used as the basis for the analysis of equipment, coolant piping, and equipment support structures for normal and upset loading conditions. The analysis is performed using a static model to predict deformation and stresses in the system. Results of the analysis given six generalized force components, three bending moments, and three forces. These moments and forces are resolved into stresses in the pipe in accordance with the applicable codes. Stresses in the structural supports are determined by the material and section properties assuming linear elastic small deformation theory.

As part of the design control on materials, Charpy V-notch toughness tests are run on all ferritic material used in fabricating pressure parts of the reactor vessel, steam generator and pressurizer to ensure that during hydrotesting and power operation these components operate in the ductile region at all times. In addition, drop-weight tests are performed and Charpy V-notch transition temperature curves are established for the reactor vessel materials.

As an assurance of system integrity, all components in the system are hydrotested at 3,107 psig prior to initial operation.

4.3.4 Pressure Relief

Signals from the pressurizer pressure control channels are used to control pressurizer spray, heaters and power-operated relief valves.

In the event of a complete loss of heat sink, i.e., no steam flow to the turbine, protection of the reactor coolant system against overpressure is afforded by pressurizer and steam generator safety valves along with any of the following reactor trip functions:

1. Reactor trip on turbine trip
2. High pressurizer pressure reactor trip
3. Overtemperature ΔT reactor trip
4. Low feedwater flow reactor trip
5. Low-low steam generator water level reactor trip.

These cases are discussed in Reference 7. A detailed functional description of the process equipment associated with the high pressure trip is provided in Reference 8.

The upper limit of overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2,500 psia and a total accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power operated relief valves during this surge.

System components whose design pressure and temperature are less than the RCS design limits are provided with overpressure protection devices and redundant isolation means. System discharge from overpressure protection devices is collected in the pressurizer relief tank in the RCS. Isolation valves are provided at all connections to the RCS.

The reactor coolant system is protected against overpressure by safety valves located on the top of the pressurizer. The safety valves on the pressurizer 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. The capacity of the pressurizer safety valves is

5. The reactor closure head is stored in a dry condition on the containment floor during refueling, allowing direct access for inspection.

6. The insulation on the vessel closure head is removable, allowing access for the visual examination of head penetrations.

7. All reactor vessel studs, nuts, and washers are removed to dry storage during refueling, allowing inspection in parallel with refueling operations.

8. Access holes are provided in the core barrel flange allowing access for the remote visual examination of the clad surface of the vessel without removal of the lower internals assembly.

9. Access holes in the reactor cavity water seal and reactor vessel cavity upper neutron shield segments provide access for the surface and visual examination of the primary nozzle safe-end welds.

10. Manways are provided in the steam generator channel head to provide access for internal inspection.

11. A manway is provided in the pressurizer top head to allow access for internal inspection.

12. The insulation covering all component and piping welds and adjacent base metal is designed for ease of removal and replacement in areas where external inspection is planned.

13. Removable plugs are provided in the primary shield concrete above the main coolant pumps to permit removal of the pump motor to provide internal inspection access to the pumps.

14. The primary loop compartments are designed to allow personnel entry during refueling operations, to permit direct inspection access to the external portion of piping and components.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests which are required by the ASME inservice inspection code. These are:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to an acceptance and repair standard to assure an adequate cladding bond to allow

later ultrasonic testing of the base metal from the inside surface. The size of cladding bounding defect allowed is 3/4 inch parallel to the weld.

2. The design of the reactor vessel shell in the core area is a clean, uncluttered cylindrical surface to permit future positioning of the test equipment without obstruction.

3. After the shop hydrostatic testing, selected areas of the reactor vessel are ultrasonically tested and mapped to facilitate the inservice inspection program.

4.5.1.2 Irradiation Surveillance Program

In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and wedge opening loading (WOL) fracture mechanics test specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and is in accordance with ASTM-E-185-82, except that tensile specimen orientation will be in the axial direction instead of the hoop direction as shown in Figure 1 of ASTM-E-185-82 and the number, type and location of specimen conform to ASTM-E-185-73. The surveillance program does not include thermal control specimens. These specimens are not required since the surveillance specimens will be exposed to the combined neutron irradiation and temperature effects and the test results will provide the maximum transition temperature shift. Thermal control specimens as considered in ASTM-E-185-82 would not provide any additional information on which the operational limits for the reactor vessel are set. The surveillance program will not include correlation monitors. Correlation monitors were used in the past because of inadequate neutron dosimeters. Present neutron dosimeters included in the capsules can be used to measure exposure throughout the life of the reactor vessel. The reactor vessel surveillance program uses eight specimen capsules which meets the requirements of ASTM-E-185-73. The capsules are located in guide baskets welded to the outside of the thermal shield as depicted in Figure 4.5-2 about 3 inches from the vessel wall directly opposite the center portion of the core. Sketches of an elevation and plan view showing the location and dimensional spacing of the capsules with relation to the core, thermal shield and vessel, and weld seams is shown in Figures 4.5-1 and 4.5-2 respectively. The capsules can be removed when the vessel head is removed, and can be replaced when the internals are removed. The capsules contain reactor vessel steel specimens oriented in the principal rolling direction and normal (transverse) to the principal rolling direction from the limiting SA-533 Grade B class 1 shell plates located in the core region of the reactor and associated weld metal and heat affected zone metal.

Pressure Vessel Code. Specific provisions were made as discussed in Section 4.5.1.1, to ensure compliance with the requirements of IS-141 and IS-142.

The use of conventional nondestructive, direct visual and remote visual test techniques can be applied to the inspection of all primary loop components except for the reactor vessel. The reactor vessel presents special problems because of the radiation levels and remote underwater accessibility to this component.

As indicated above, the only sophisticated remote inspection equipment currently required is for inspection of the reactor vessel. The baseline inspection was performed by Westinghouse utilizing a remote reactor vessel ultrasonic inspection tool which will perform the code required inspection of the circumferential and longitudinal shell welds, the flange to vessel weld, the ligaments between the flange holes, the nozzle to vessel welds, and the nozzle to safe-end to pipe welds.

The vessel inspection tool used for preservice inspection has two major structural components, the center column assembly which is supported and aligned from the vessel internals support flange by the head assembly. These two structures form the rigid base assembly from which all the scanning arm and drive assemblies are mounted and operated. Two configurations of the tool can be arranged depending on the areas of the vessel to be examined. In one configuration the scanning arm and transducer array necessary to examine the vessel shell welds are mounted on the main carriage assembly. The main carriage assembly can traverse the full length of the vessel up and down the center column and also provide a 360 degree circumferential rotation around the inside of the vessel. In the second configuration, the nozzle scanning assembly is mounted beneath the main carriage and can be rotated for 360 degrees to provide alignment with any of the vessel nozzles. The tool, in this configuration, can be installed in the vessel without removal of the lower internals package. The scanning attachment for the examination of the vessel flange weld and ligaments can be installed on the tool in either of the two configurations described above. Figures 4.5-4 and 4.5-5 show the pre-service inspection tool in both these configurations.

For reactor vessel scanning, a data acquisition system is used which combines simplicity with operational reliability and adaptability. It employs an electronic system with a receiver or data channel for each transducer unit. The signal received from the transducer is transmitted through an electronic distance amplitude correction device and depending on the amplitude, gated through individual transigates to a printer. Simultaneously with the gated signal, information is received from the position indication encoder system which provides position coordinates. An audio/visual alarm is also triggered. The resultant indication is printed on a recording device together with its position reference.

Following the completion of the scan of all the areas scheduled for inspection, the tool operator(s) will, operating on manual control,

return the transducer array to each of the indication position coordinates and fully evaluate the nature of the indication to sufficient extent to be able to determine the size, shape, and orientation. Special transducer arrays with variable angle search units were provided to assist in this activity during the pre-service inspections. The ongoing inservice inspections of the Reactor Vessel shall be done in accordance with the requirements of 10 CFR 50.55a(g), Inservice Inspection.

For the manual ultrasonic scanning of required components the licensee has reviewed and approved all inspection procedures to insure that all inspection results are recorded in a consistent and congruent manner to avoid ambiguity in interpretation.

The data from the various baseline and inservice inspections, collected in accordance with the applicable above-referenced procedures, have been collected into comprehensive reports tabulating all the results. The reports describe the scope of the inspection, the procedures utilized, the equipment utilized and names and qualifications of the personnel and all the examination results including all instrument calibration criteria in sufficient detail to ensure repeatability of each examination.

The only areas where it is expected that high radiation levels will prohibit the access of personnel for direct examination of component areas or systems, is the reactor vessel. The special design provisions and tooling required to perform the code required examinations in these areas have been discussed above. Westinghouse is carrying out a continuing program of radiation surveys during refueling programs in operating plants to ensure that any possible future problem areas are detected at an early stage. Should additional experience in the maintenance and inspection of operating plants indicate that other areas exist where access will be either limited or impossible, steps will be taken to develop any remotely operated inspection equipment considered necessary to meet the commitments of examinations defined in the Technical Specifications.

The detailed inservice inspection program is presented in the Beaver Valley Power Station Unit 1 Ten Year Plan detailing the ASME Section XI requirements. The preservice inspection program was based on ASME Section XI dated July 1, 1971. Both programs reflect a modified inspection program based on component accessibility and local radiation restrictions. The results from the various inspections and the changes in inspection technology will be evaluated and incorporated into the inspection program on a continuing basis to ensure the integrity of the systems scheduled for inspection.

TABLE 4.1-2

REACTOR COOLANT SYSTEM DESIGN PRESSURE SETTINGS (PSIG)

Design Pressure	2,485
Operating Pressure	2,235
Safety Valves	2,485
Power Relief Valves	2,335
Pressurizer Spray Valves (begin to open)	2,260
Pressurizer Spray Valves (full open)	2,310
High Pressure Trip	2,385
High Pressure Alarm	2,310
Low Pressure Trip	1,920*
Low Pressure Alarm	2,185
Hydrostatic Test Pressure	3,107
Backup Heaters On	2,210
Proportional Heaters (begin to operate)	2,250
Proportional Heaters (full operation)	2,220
SIS Low Pressure Injection (Operational Setpoint)	1,845

* Low Pressure Trip (Operational Setpoint) 1,945

TABLE 4.1-10

SUMMARY OF REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

Normal Conditions	Occurrences
Heatup and Cooldown at 100°F/hr (pressurizer cooldown 200°F/hr)	200 (each)
Unit Loading and Unloading at 5 percent of full power/min	18,300 (each)
Step Load Increase and Decrease of 10 Percent of Full Power	2,000 (each)
Large Step Load Decrease	200
Steady State Fluctuations	infinite
Upset Conditions	
Loss of Load, without immediate turbine or reactor trip	80
Loss of Power (blackout with natural circulation in the RCS)	40
Loss of Flow (partial loss of flow one pump only)	80
Reactor Trip from Full Power	400
Operational Basis Earthquake (20 earthquake of 20 cycles each)	400
Faulted Conditions	
Main Reactor Coolant Pipe Break*	1
Steam Pipe Break	1
Steam Generator Tube Rupture	(1 included in upset condition item 4 above, Reactor Trip from Full power)
Design Basis Earthquake	1

* Leak-Before-Break assumed for design of component supports, reactor cavity water seal, upper reactor cavity neutron shield segments and pipe stress.

SECTION 5

CONTAINMENT SYSTEMS

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5. Safeguards area

6. Main steam valve area.

The maintenance of integrity of the Seismic Category I piping systems after differential settlement has occurred and while experiencing loading due to differential movement of equipment and structures during seismic disturbance is ensured by designing the piping, hangers and equipment supports to accept these loadings while experiencing stress values that are below those allowed by ANSI B31.1.

Table 5.2-17 provides the structures, systems and components within the containment that are not designated Seismic Category I.

Other structures, systems and components within the containment whose potential failure could compromise the functional capability of surrounding Seismic Category I components are classified as Seismic Category II in Appendix B and are designed to withstand the combined effects of normal operating loads and earthquake loads. By the static analysis methods outlined in Section B.2.2 structural elements, anchorages and restraints are designed to preclude the possibility of Seismic Category I components becoming endangered. Analysis of Seismic Category II components is not intended to assure their functional capability.

5.2.2 Design Basis and Loading Criteria

The structural design of the containment is based upon:

1. Shielding requirements

2. The pressure and temperature generated by the DBA (see Section 14)

3. The Operational and Design Basis Earthquake (see Section 2.5 and Appendix B)

4. The maximum calculated core thermal power level of 2,713 MWt.

The temperature and pressure resulting from the DBA are selected as the containment design basis, since the normal operating conditions would result in lower design temperatures and pressures. The containment structure is also designed for subatmospheric operation

and for a maximum leakage of less than 0.1 percent per day of the weight of containment air at the calculated peak containment pressure of 40.0 psig as given by the limiting LOCA analysis.

During normal operation, the containment air partial pressure is maintained between 8.9 and 10.5 psia and the containment air temperature can range between 75°F minimum and 105°F maximum, depending upon the temperature of the available river water. The containment is accessible for inspection and minor maintenance during operation without altering the normal subatmosphere pressure, provided that personnel are supplied with oxygen-enriched breathing air equipment.

The design pressure and temperature for the containment are 45 psig and 280°F. This pressure is chosen by using the LOCTIC computer program (Sections 5.2.2.4 and 14), which calculates the containment pressure transient of the DBA. The results of the pressure transient calculations, with minimum engineered safety features, are described in Sections 14.2 and 14.3. The design pressure for the containment exceeds the maximum calculated pressure.

Localized pressure pulse effects are considered in the design of the containment structure. These effects result from a double ended pipe rupture or split pipe rupture at any location in either the reactor coolant loops or main steam lines. All closed or restricted spaces subjected to these localized pressure pulses are designed with sufficient vented openings to limit the pressure differentials between adjacent compartments. All structural components, walls, floors, and beams in these spaces are designed to withstand the pressure differential as part of their design loading.

The concrete containment structure including the interior compartments and shield wall is designed by ultimate strength methods conforming to American Concrete Institute (ACI) Standard 318-63, Part IV[11]. Design load criteria, based on ACI requirements and stated below, conform to current containment design practice. The combinations of dead load, pressure, and earthquake or tornado loading, expressed in the design criteria, contain varying load factors for pressure and earthquake forces. The total loading resulting from the summation of any one of the combinations of these loads causes a maximum stress condition, depending upon the type of stress and member under consideration.

In accordance with ACI 318, Section 1506, forces due to wind or tornadoes and those due to earthquakes are not considered to occur at the same time. Normal wind forces, as recommended by ASCE Paper No. 3269, as referenced in Section 2.7, do not govern the design. Buoyance, caused by flooding, is a factor in design only during construction of the containment (Section 5.2.2.5).

The effect of creep, shrinkage and stress concentration on the modulus of elasticity and Poisson's ratio on reinforced concrete is of small consequence during the short term loading incurred as a result of the DBA, and is therefore not included in the analysis of design of the conventionally reinforced concrete containment.

Temperature conditions within the containment during a LOCA DBA are shown in Figure 14.3-58. Temperature conditions within the containment during a MSLB DBA are shown in Figure 14.2-35. The containment liner temperature following the MSLB DBA is shown in Figure 14.2-36. The temperature increase in the rebars will decrease the modulus of elasticity of the rebars only slightly (less than 3 percent). This reduction is within the capacity reduction factors listed below for variation in material strengths and workmanship. In addition, the DBA pressure will be reduced significantly before the rebar is affected by the temperature rise.

The effect of temperature, shrinkage and creep on the concrete modulus does not affect the analysis of the containment shell and dome since the concrete is assumed to be cracked during the DBA loading. The containment mat, 10 ft thick, is insulated by approximately 2 ft of overlying concrete. The DBA produces only short term loading on the mat and creep is not significant.

Concrete is considered to offer resistance only near the base of the containment. The temperature gradient through the concrete shell thickness of 48 inches is shown in Figure 5.2-28. Since the maximum design pressure occurs within the first 20 seconds, the temperature effects are negligible.

The load capacity of concrete members that are subject to tension is based on the guaranteed minimum yield strength of the reinforcement steel.

Load capacities of flexural and compression members are determined in accordance with ACI 318-63. Load capacities so determined are reduced by a reduction factor multiplier, θ, to compensate for small adverse variations in material and workmanship. The reduction factors are provided in Table 5.2-18.

Stress and strain limits resulting from the loading criteria conform to the requirements of ACI 318-63, Part IV-B. Principle reinforcing steel used in the construction of the containment structure has a minimum yield strength of 50,000 psi and a minimum ultimate strength of 70,000 psi. Concrete has a specified 28 day compressive strength of 3,000 psi. The analyses of the structure for static loading and for dynamic loading are covered in Section 5.2.2.5. Design load values relative to the site are summarized in Section 2.7.

Structural steel sections of the containment interior are designed in accordance with the American Institute of Steel Construction, AISC-63[12], except that the seismic loading referred to in AISC-63, Part 1, Paragraph 1.56 is considered as the OBE. Allowable stresses are factored as follows:

1. OBE: 33 percent increase

2. DBE: 90 percent of the specified minimum yield strength for structural steel.

The designed ultimate load capacity of the containment structure, as modified by the safety provisions of ACI 318-63, Section 1504, is not less than that required to satisfy the structural loading criteria for various components described in the subsequent sections.

5.2.2.1 Containment Shell Structural Loading Criteria

1. Maximum hypothetical loading for the Design Basis Accident (DBA) only with a 1.5 factor for the DBA pressure:

$$D(1.0 \pm 0.05) + 1.5P + T + TL_{(1.5\ P)} \qquad (5.2\text{-}1)$$

2. Maximum hypothetical loading for the 1.25 factored DBA and 1.25 factored Operational Basis Earthquake (E):

$$D(1.0 \pm 0.05) + 1.5P + T + TL_{(1.25P)} + 1.25E \qquad (5.2\text{-}2)$$

3. Maximum hypothetical loading for the unfactored DBA and unfactored Design Basis Earthquake (E'):

$$D(1.0 \pm 0.05) + 1P + T + TL_{(P)} + E' \qquad (5.2\text{-}3)$$

4. Maximum hypothetical loading for tornado only:

$$D(1.0 \pm 0.05) + T + C \qquad (5.2\text{-}4)$$

Where: D = Dead load of structure and equipment, including effect of earth, hydrostatic pressures, ice, and snow loads, when their effect increases the resultant stresses. To provide for variations in the assumed dead load, the coefficient for the dead load component is adjusted by ±5 percent, as indicated in the above formulas, to provide the maximum stress levels.

P = Pressure load resulting from the DBA

T = Load due to maximum temperature gradient through the concrete shell and mat for normal operating conditions

TL = Load exerted by the liner, when it is exposed to the temperature associated with the pressure resulting from a DBA

E = Loading from "Operational Basis Earthquake" (Section 2.5)

E'= Loading from "Design Basis Earthquake" Section 2.5.

C = Load due to negative pressure and horizontal wind velocity resulting from assumed tornado (Section 2.7).

5.2.2.2 Containment Interior Loading Criteria

The design pressures for the interior compartments of the containment structure are determined by the numerical integration of finite differential equations defining heat and mass flows into and out of the interior compartments, assuming a double-ended rupture of the primary coolant pipe within the compartment.

The time dependent pressure differential curves for the steam generator cubicles are shown on Figures 14.3-86, 14.3-87 and 14.3-88 for a hot leg double-ended rupture. The containment peak pressure curves are shown on Figure 14.3-55 for three types of double-ended ruptures. A comparison of these curves shows that peak containment pressure occurs later than the peak pressure of the steam generator cubicles. It is at this later time, that the foundation mat is under maximum loading from the accident pressure. Force from internal cubicle pressure loading is transmitted to the mat in part by the column under the cubicle floor which supports the steam generator. The loading due to cubicle pressure is well in advance of the maximum foundation mat loading. Maximum cubicle loading and maximum foundation loading cannot occur at the same time. The foundation mat is designed for either the maximum cubicle pressure loading or the factored containment overpressure loading.

The design of the steam generator cubicles, including the discontinuities, utilizes the same ultimate strength design methods described for the design of the exterior structure. The compartments are designed to have a load capacity adequate to resist:

$$D\ (1.0 \pm 0.05) + R + T + P' + E' \qquad (5.2\text{-}5)$$

where: D = Dead load of structure and equipment

R = Double-ended or longitudinal pipe rupture thrust on structure as a function of time (including jet forces, as applicable)

T = Load due to maximum temperature gradient through the concrete from increased temperatures resulting from the pipe rupture and pressure buildup

P'= Pressure buildup from the expansion of the fluid released from the ruptured pipe as a function of time

E'= Design basis earthquake loading

For design purposes, the maximum values of R and P' are assumed to occur concurrently.

The strength capacity of reinforced concrete sections is determined by ultimate strength provisions of ACI 318-63 incorporating the load capacity reduction factors used for the containment structure design. An elasto-plastic analysis is conducted on the steam generator cubicle walls to ensure that they have sufficient ductility to absorb the energy of the jet impingement forces.

The steam generator support columns together with other support elements of the structure are designed to carry safely the maximum axial forces, moments and shears which are developed from studies of the postulated pipeline ruptures. These loadings are decaying forces which are maximums at the beginning of the accident when the mat is not loaded by accident pressure and equal to zero when full accident pressure on the mat occurs.

Time dependent temperature rise in the cubicle resulting from accident has negligible effect on the mat.

The radial walls, crane wall and floors which define the steam generator cubicles are designed for the differential pressures and loads stated above.

The temperature differentials are negligible due to the fact that the containment temperature is of the order of 140°F within 30 minutes and as a result only a few inches of concrete would be affected by the transient.

The primary shield wall which houses the neutron shield tank and the reactor is designed for the following loading conditions:

1. Dead load

2. Transient internal pressure due to pipe rupture in the reactor cavity varying from 146.2 psi at the coolant pipe nozzle penetration to 20 psi at the bottom of the shield tank and 0 psi at the top of the primary shield wall

3. Average steady-state temperature rise in wall from 50°F to 120°F

4. Operating gradient temperature across the wall thickness equal to 23°F

5. Accident transient temperature on wall face equal to 160°F

6. Induced forces (moment and shear) due to operating thermal gradient (25°F) and average steady-state temperature rise (30°F) in the foundation mat

7. Seismic shear and moment on the wall

8. Reactions of reactor vessel, steam generator and reactor coolant pump supports due to pipe rupture

9. Load of 2563 K applied to 48 inch grouted area between shield tank and primary shield wall, located at the top of shield tank, due to seismic and pipe rupture loads on reactor. The loading conditions 1 through 8, as pertinent, are combined with the general containment loading conditions, as given in Section 5.2.2.1 to produce the most severe design combinations.

For the design of the foundation mat, the factored loads stated in Section 5.2.2.1 are superimposed upon normal operating loads which include the thermal conditions and the normal and accident forces induced by the primary shield wall, the crane wall, steam generator support columns and the containment wall.

The design of the mat includes the effect of change of distribution of soil pressure due to overturning moment from earthquake loadings.

5.2.2.3 Reactor Coolant System Equipment Supports

5.2.2.3.1 Design Basis

The reactor coolant system includes the reactor vessel, three steam generators, three reactor coolant pumps and a pressurizer. Structures are provided to support this equipment to ensure system integrity during normal operation and Design Basis Accident conditions.

All supports in the reactor coolant system are designed to withstand dead weight and the Design Basis Earthquake acting simultaneously with an instantaneously applied pipe rupture. Two types of piping failures are considered separately: (1) a double-ended rupture and (2) a longitudinal rupture on either the horizontal or vertical axis of the pipe. These failures are assumed to occur in either the pressurizer surge piping or the main steam piping. The value of the pipe thrust for any reactor coolant pipe rupture is based on Westinghouse blowdown analysis. Static design loads for the pipe thrust are listed in Table 5.2-1. These loads include a value of two for the dynamic load factor. The supports were initially analyzed for these loadings simultaneously with the Design Basis Earthquake, and all stresses remained within 90 percent of the minimum yield point of the structural material used. A dynamic analysis was then performed to validate the static analysis.

All welding is in accordance with the American Society for Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section IX, and all welds are examined by either radiographic, ultrasonic, dye penetrant, or magnetic particle techniques, depending on the material, and the state of stress at the weld.

5.2.2.3.2 Description

<u>Reactor Vessel Support</u>

The reactor vessel is supported by six sliding foot assemblies mounted on the neutron shield tank as shown in Figure 5.2-2. These foot assemblies were fabricated from modified American Iron and Steel Institute, AISI 4330 forgings. The support feet are designed to restrain lateral and rotational movement of the reactor vessel for simultaneously applied Design Basis Earthquake, pipe rupture loads and dead weight, while allowing thermal expansion. The neutron shield tank is a double walled cylindrical structure of American Society for Testing Materials (ASTM) A-516 steel which transfers the loadings to the heavily reinforced concrete mat of the containment structure and to the primary shield wall. The tank also serves to minimize gamma and neutron heating of the primary concrete shield, and to attenuate neutron radiation outside of the primary shield to acceptable limits.

The shield tank is securely fastened down by anchor bolts. Overturning moments and horizontal forces which are induced on the tank during normal operation or accident condition are taken in part by the reinforced concrete primary shield wall poured locally around the neutron shield tank. Any resulting vertical uplift force is taken by the anchor bolts.

The tank is completely shop fabricated and is constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII. However, a code stamp is not required. All welding, welding procedures, and welding operators' qualifications are in accordance with the ASME Code, Section IX.

All welds are inspected by either radiographic, dye penetrant, or magnetic particle techniques.

After fabrication, the completed tank is subjected in the vertical position to a hydrostatic test of 15 psig as measured on top of the tank. In no case does the hydrostatic pressure exceed 35 psig anywhere in the tank. The tank is also leak tested with dry air at 20 psig, by applying soapsuds to all welds accessible from the outside of the tank.

Steam Generator and Reactor Coolant Pump Supports

The steam generator and reactor coolant pump supports are shown in Figures 5.2-3 and 5.2-4. The materials used are for the most part commercially available structural shapes of ASTM A-36 steel. High strength quenched and tempered alloy steels are used for local attachments at the steam generator and reactor coolant support pads, in the hydraulic snubbing assemblies, in the pump support columns, and in the steam generator struts.

The steam generator support system consists of an upper support ring and a lower support frame. The upper support ring is shimmed in the cold condition to the steam generator with a 0.050 inch radial gap to permit full pressure expansion of the steam generator, and insulated so that it expands thermally as the steam generator is brought up to temperature. The upper support ring transmits horizontal forces from the steam generator through four tangential load trains to the reinforced concrete charging floor. The operating floor in turn transmits these horizontal forces to the reactor shield wall, the crane wall, and to the cubicle walls, where, through shearing actions, they are further transmitted downward to the mat. The tangential load trains from the upper support ring to the operating floor are equipped with hydraulic snubbing cylinders and struts. The snubbers permit limited slow motion of the steam generator to allow for thermal expansion of the reactor coolant piping from the reactor to the steam generator. The cylinders, however, react to resist suddenly applied forces which occur from earthquake or pipe rupture conditions.

The lower support frame is a weldment fabricated of ASTM A-36 structural steel shapes. The support frame slides on lubricated bearing plates located under each corner column in order to permit thermal expansion of the reactor coolant piping from the reactor to the steam generator. The four columns also transmit vertical forces from the steam generator to the cubicle floor. The support frame has large shear blocks on two sides which fit into embedments in the cubicle floor. These shear blocks guide the lower support frame along a direction radial from the reactor and transmit forces perpendicular to this motion into the embedments in the cubicle floor. The attachment of the lower support frame to the four pads on the steam generator bottom head permits radial thermal expansion of the steam generator.

The reactor coolant pump is mounted in a support frame which permits radial thermal expansion of the pump feet. The frame is held above the cubicle floor by three pin-ended columns which provide vertical support while allowing free movement in the horizontal plane.

The vertical forces applied to the cubicle floor are beamed-out in the reinforced concrete to the edges of the floor where the vertical forces are transmitted to the surrounding walls. The vertical forces transmitted to the cubicle walls are in turn beamed-out to the crane wall columns and to the shield wall where they are carried downward to the mat. A 5 ft-0 inch square column between the cubicle floor and the mat beneath the steam generator provides an additional load path which transmits some of the vertical forces directly from the cubicle floor to the mat.

Horizontal forces applied to the cubicle floor act as a torsional moment about the centerline of the reactor. This moment is transmitted to the mat by torsional shearing forces in the shield wall and by shear forces in the crane wall columns and in the column below the steam generator.

The base of the shield wall (Figure 5.2-6) is designed to pass on to the mat the shear stresses initiated on it by mat deflection.

It also has the capability of transmitting horizontal seismic loading on the internal structure to the mat. The 3 inch by 6 inch bridging bars of the crane wall and the shield wall also participate as far as the stiffness and straining of the structure permits.

Pressurizer Support

The pressurizer vessel is mounted to a rigid ring girder which is suspended from the operating floor by four hanger columns as shown in Figures 5.2-7 and 5.2-8. To offset the flexibility of the hanger columns, two brackets welded to the ring girder slide in guides rigidly attached to the bulkhead which restrain all motions except vertical translation. In addition, anti-sway brackets welded to the shell of the pressurizer fit into striker plate assemblies embedded in the concrete floor close to the center of gravity of the vessel. These brackets permit the pressure vessel to expand vertically but restrain horizontal displacements.

The ring girder is fabricated from ASTM A-516 Grade 70 steel, or equivalent,[43] of 38,000 psi minimum yield point. The striker plate assemblies are fabricated from AISI 4340 steel, or equivalent,[43] heat treated to 120,000 to 140,000 psi yield point. The hanger columns are fabricated from ASTM A-106, Grade B, or equivalent,[43] pipe. The majority of the fasteners and shear pins used in the support are fabricated from either ASTM A-193, Grade 7, or AISI 4340, heat treated, depending on the stress level.

5.2.2.3.3 Evaluation

Steam Generator and Reactor Coolant Pump Supports

To determine dynamic loads on the Steam Generator and Reactor Coolant Pump supports, the analytical model in Figure 5.2-25 was employed. This model accounts for the dynamic behavior of steam generator and reactor coolant pump, as well as associated piping and supports. The mass and stiffness characteristics of each of the major subsystems were accurately transformed into a lumped parameter system. The STARDYNE program, developed by Mechanics Research, was employed to analyze the dynamic response of the system due to pipe rupture and earthquake motions.

Blowdown data supplied by Westinghouse were used to perform the pipe rupture analysis. These data consisted of time history forces which included jet thrust at break location and internal hydraulic forces resulting from the propagation of shock waves and flow inertias. For the seismic analysis, the total response was evaluated by taking the square root of the sum of the squares of the individual modal contributions.

Since the dynamic model shown in Figure 5.2-25 is an idealization of the support structure and equipment shown in Figure 5.2-3, the results of the dynamic analysis could not be used directly. Instead, the time history of displacements obtained from the dynamic analysis was applied to a more detailed static analysis model to obtain internal loads and stresses in the support structure, loads on the equipment support pads, and loads on the reinforced concrete structure which interface with the equipment supports. This stress model which is shown in Figure 5.2-26 was modeled and analyzed using the STRUDL[13] program (developed by M.I.T. Civil Engineering Department).

This analysis was completed and the results compared to the original static analysis, indicating that the design loads were conservative for the majority of the cases. Where the dynamic loads were larger than the design loads, detailed analyses were performed and design modifications made where necessary to ensure the integrity of the structure. Tables 5.2-2, 5.2-3, and 5.2-4 contain static and dynamic loads for some of the components. Thermal gradients produced in the supports by pipe rupture jet impingement were also investigated. This and other areas have been examined for the effects of jet impingement thermal gradient and forces.

Reactor Vessel Supports, Neutron Shield Tank and Pressurizer Supports

For the determination of dynamic loads on the reactor vessel supports, neutron shield tank and the pressurizer supports, an analysis technique was applied which is similar to that used for the steam generator and reactor coolant pump supports. However, for the reactor vessel supports and neutron shield tank the STRUDL program was employed.

The dynamic model and the stress model used in the analysis of reactor vessel supports are shown in Figures 5.2-10 and 5.2-27, respectively. The dynamic model employed for the pressurizer support is shown in Figure 5.2-9. For this system no stress model was required since the dynamic model was sufficiently detailed to directly compute stresses and loads.

5.2.2.4 Bases for Containment Analyses

To ensure that the containment performs the desired function of protecting the public against gross equipment failures, analyses have been performed assuring the double-ended displacement ruptures of piping in the reactor coolant system. These ruptures have been assumed to occur in conjunction with loss of all off-site power.

They are defined in the Design Basis Accident (DBA) descriptions in Sections 14.2 and 14.3.

The design of an atmospheric containment is concerned with the peak containment pressure following the double-ended rupture of a pump discharge pipe. Since, for a subatmospheric containment, leakage ceases when the containment pressure is below atmospheric, two additional points in the containment pressure transient are important.

The first is the time required to depressurize the containment, which together with a safety factor is the basis (time) for the Post DBA site dose calculation (Section 14.3.5). The second is the maximum containment pressure following depressurization. This value must be such that the containment remains depressurized under all credible atmospheric pressure variations. These are the criteria by which the containment depressurization system and the containment are designed.

The BVPS-1 containment volume, heat sink capacity, and engineered safety features are designed to:

1. Yield a maximum peak calculated containment pressure of 44.2 psig. In order to meet this condition, the containment is designed to withstand, without loss of integrity, a maximum pressure of 45 psig and a maximum containment atmosphere temperature of 348.5°F

2. Depressurize in 60 minutes or less, thus terminating all outleakage

3. Remain depressurized following the double-ended displacement rupture of a reactor hot leg, cold leg reactor coolant pump suction pipe, or split break rupture from a MSLB.

The results presented in Section 14.3 and analyses of other less serious accidents (Section 14.2) indicate that the bases for design are adequate, and that margin is allowed for uncertainties in design.

5.2.2.5 Static and Dynamic Analyses

5.2.2.5.1 Loads

The containment structure is analyzed and designed for the following loads, which are multiplied by load factors and are added together in the manner detailed in Section 5.2.2.1.

Lateral Earth Pressure

The top of the containment mat is approximately 44 ft below ground elevation; therefore, active and passive earth pressures exert an influence during operation and DBA conditions, respectively. The lateral earth pressure due to seismic response is evaluated in Section 2.6.4.4.

Horizontal and Vertical Earthquake

These forces are determined by means of the dynamic analysis described in Appendix B. The stresses resulting from the horizontal and vertical earthquakes are added algebraically.

Hydrostatic Pressure and Buoyancy

Hydrostatic pressure occurs only during flood stages since the groundwater at the site is normally well below the top of the containment mat. The groundwater is at about El. 666 ft when the river is at pond level El. 664.5 ft. Hydrostatic pressure, when combined with the lateral earth pressure, does not cause maximum stress conditions in the cylinder walls. Loading on the containment during the probable maximum flood (PMF), only exerts a maximum hydrostatic pressure of 17.4 psi at the base of the containment. Buoyancy of the containment was not a design problem, as conditions favoring it could occur only during the early construction period. In the unlikely event of a probable maximum flood exceeding the cofferdam height, buoyancy of the partially completed containment would have been averted by flooding the structure with water. When the containment concrete work was completed to about El. 745 ft, the structure had enough dead load to balance the buoyancy due to a probable maximum flood. Flood stages and the wave resulting from a dam break upstream are discussed in Section 2.3.

Dead and Live Load

Dead load includes the total weight of the structures, including equipment. Live loads, such as snow and ice, are included when their effect increases the resultant stresses.

Internal Pressure

During normal operation, a pressure below atmospheric is maintained inside the containment. The DBA (MSLB) internal pressure is 44.2 psig. The test pressure used during the tests to determine the integrity of the containment structure is 15 percent greater than the design pressure of 45 psig.

The barriers are designed so that they will not be penetrated by the postulated missiles. The steam generator shell is also ample to resist penetration of the postulated missiles. The lower steam generator shell connecting lines are routed so that they are not in the direct path of the postulated missiles.

A missile shield structure is provided over the control rod drive mechanisms to block any missiles which might be associated with a fracture of the pressure housing of any mechanism. A concrete slab with steel facing is located on top of the control rod drive mechanism housing, as close as possible to the housing to limit the velocity of the ejected missiles, to minimize the probability of missiles missing the shield and striking the containment liner, and to minimize the probability of missiles ricocheting and damaging other control rod drive mechanism housings.

The housing plug is calculated to be stopped by the missile shield steel plate using the method illustrated in ORNL-NSIC-5 page 6.158, a value of 60,000 psi for the target plate ultimate tensile strength and 14 inches for the side length of the "square window". The missile shield steel plate is at least 1 inch thick.

The critical kinetic energy required for drive shaft penetration of the missile shield steel plate is calculated as recommended in ORNL-NSIC-5 page 6.158, using a value of 60,000 psi for the target plate ultimate tensile strength and 14 inches for the side length of the "square window". This value is deducted from the drive shaft kinetic energy at the time of impact (Table 5.2-8 values), and the new reduced drive shaft velocity is determined. The depth of penetration in the concrete slab is then calculated according to Navdocks P-51, April, 1951 and a slab thickness of at least 3 times the depth of penetration is chosen as a design value.

For the case of housing plug and drive shaft impact, which is the design case, it is assumed that the plug partially perforates the steel plate. The drive shaft then hits the plug and pushes it through the non-perforated steel plate layer and into the concrete. One of two approaches is then adopted. The first is to use the concrete slab thickness found above and to make the steel plate thickness equal to one inch plus the plug perforation depth. This will overestimate the concrete thickness because the drive shaft pushes the plug instead of penetrating directly (plug OD is 2.75 inches, drive shaft OD is 1.75 inches).

The second approach is to use a 1 inch steel plate thickness, but increase the concrete slab thickness to ensure that at least three times the depth of penetration is chosen as a design value.

For the missile of drive shaft latched to drive mechanism, the critical kinetic energy for perforation of a 1 inch steel plate is 100,000 ft-lbs. Therefore, no perforation is expected.

To protect against valve bonnet missiles postulated in the region where the pressurizer extends above the operating deck, a barrier is built surrounding that part of the pressurizer. Penetration calculations are made to ensure that the postulated missiles would be stopped.

The ability of the reactor compartment walls and the operating deck is evaluated for the postulated instrumentation assembly and pressurizer heater missiles. Generally, the minimum thickness of the reactor compartment walls and the operating deck is 2 feet of concrete. Calculations based on this thickness and the given missile characteristics show that the critical velocity required to penetrate is at least twice the maximum anticipated velocity.

All missile barriers are also designed to withstand the dynamic impact loads. The energy method(7), the momentum method(8), or an empirical method(9) is used.

Based on a kinetic energy and impact area comparison of all credible missile, the tornado generated missile (telephone pole) has the highest kinetic energy and relatively small impact area. The telephone pole has a kinetic energy in the order of 2.5×10^6 ft-lb impacting an area of 150 square inches, while all other credible internally generated missiles (such as flanges, bolts, motor/pump couplings) have kinetic energy in the order of 3×10^3 ft-lb impacting an area of 5 square inches. Calculations provided in Reference 41 have been performed for various types of missiles. For a missile with 3×10^3 ft-lb of energy and an impact area of 5 square inches, the concrete penetration is about 11 inches. A minimum of 24 inches is provided for protection against the tornado missile.

The effect of internally generated missiles, therefore, is less than half that of the tornado generated missile. Each piece of safety related equipment with the exception of the following is separated from all other equipment by a missile-proof cubicle:

1. Refueling water tank (QS-TK-1)
2. Leak detection fans
3. Quench spray pumps
4. Auxiliary feed pumps.

For conservatism, the missile protection in each of these cases is 24 inches, the same thickness required to protect against the tornado generated missile, and therefore, each piece of this equipment is protected from internal and other external missiles.

The effect of missiles on pipe runs and cable runs to, or from, safety-related equipment has not been considered because of the physical separation of the redundant trains.

For the equipment not protected by individual concrete cubicles, a review shows that this equipment is situated in large open areas with relatively few missile generating pieces of equipment nearby. In the case of the auxiliary feed pumps, equipment capable of generating missiles is not located in the missile-protected cubicle with the two electric drive and one steam drive pumps. Because of the high quality inherent to safety related equipment, missiles from this equipment are not considered. The two quench spray pumps share an exclusive cubicle and, as such, are not considered susceptible to internally generated missiles for the same reason as the auxiliary feed pumps.

The leak exhaust fans are located on the 768 ft-7 inch elevation of the auxiliary building. The fan location with respect to the missile generating equipment in the area and the low energies of feasible missiles for the surrounding equipment make it impossible to damage more than one of the leak detection fans. The redundancy of the system is considered adequate missile protection.

In the case of the refueling water system, missile protection is considered unnecessary. Since the tank is needed only in the short term after the Design Basis Accident, it is made seismic. It is not required in the long term, and since a tornado is not postulated for 24 hours after the accident, no missile protection is provided.

The possible missile generation (pressure reducing valve) from the propane storage facility and the effect on the safety-related equipment in the area are presented in Table 5.2-15.

A brief description of various types of pressurized gas containers listed in Table 2.1-15 is presented below:

1. The gas bottle storage facility is provided for storage of various gas bottles in a nonfire hazard area. The area is policed by plant security personnel regularly to monitor housekeeping and overall physical security.

   All bottles are provided with safety relief devices for overpressure protection to meet Department of Transportation and Compressed Gas Association (CGA) requirements in the event of excess pressurization due to fire.

   The safety relief devices fall under three different categories: (a) a frangible Type A rupture disk, usually of metal, which bursts at a predetermined pressure; (b) a fusible plug of suitable low melting material to melt at a predetermined temperature to permit escape of the gas; or (c) a combination frangible disk-fusible plug, designed to rupture at a predetermined pressure when the melting point of the plug has been reached.

The minimum flow capacity of these rupture devices, as specified in Compressed Gas Association pamphlet S-1.1 is to prevent the pressure from exceeding 80 percent of minimum cylinder burst pressure for DOT-42 cylinders and 4,500 psia for DOT-3E or BTC-42 cylinders.

Cylinders below a certain length (usually 65 inches) are required to have only one safety relief device per bottle. Bottles over this length require a minimum of two relief devices at opposite ends to provide adequate response to temperature conditions.

A single failure of the cylinder's overpressurization system has been considered for possible missile generation as presented in Table 5.2-15.

2. Each CO_2 fire protection system is normally maintained at 300 psia. Each system is provided with a bleeder valve which opens at 341 psia. If pressure continues to rise above the bleeder valve capacity, a safety relief valve will open at 357 psia. This pressure relief valve will offset an increase in pressure above 358 psia resulting from high ambient temperature conditions and almost all insulation being removed. Under loss of refrigeration, the bleeder valve can maintain self-refrigeration of the CO_2 unit. The two CO_2 units are located in areas of very low fire hazard.

3. Each control room emergency pressurization bottle is provided with a rupture disk for overpressurization protection. The pressurized bottles and piping are located in areas not subject to fire hazard. Rupture disks are provided on each tank to prevent any pressure increase beyond 1.5 times the design pressure.

4. The bulk hydrogen storage vessels and hydrogen bottle storage pad are located in areas not subject to fire hazards. The locations of the hydrogen bulk storage and Hydrogen bottle storage pad conform to OSHA requirements for outdoor storage of H2 systems. (Table H.2, paragraph 1910.103 of Federal Register, "Occupational Safety and Health Administration," Volume 37, Number 202, Part A.)

The bulk hydrogen storage system is provided with relief valves to prevent pressure buildup in the hydrogen storage vessels beyond 110 percent of design pressure for system fill operations or rises in ambient temperatures. In addition, each tank is supplied with rupture disks as additional pressure protection to prevent the pressure from exceeding 1.5 times the design pressure of the vessel.

In summary, single failure of any of the protective features (administrative control of housekeeping or thermo/pressure relieving devices) will not in itself represent a compressed gas vessel explosion hazard.

A description of the approach used for (1) missile identification, (2) location of missile sources with respect to safety-related equipment, (3) size, weight, and kinetic energy of missiles, and (4) protection against missiles, is given as follows:

1. All safety related equipment was identified on a plant layout drawing.

2. It was noted that a large percentage of the equipment was isolated from all other equipment by two foot thick missile proof concrete walls (missile proof wall) capable of stopping a design basis accident (150 mph 1870# phone pole). Experience indicates that missiles from equipment such as pump motor couplings, pump drive turbine blades, compressor heads or valves and gage attachments to pressurized gas bottles do not have kinetic energies/impact areas equivalent to the design basis missile. In light of this experience, no further investigation was considered required for the isolated equipment unless studies of the unisolated equipment indicated that internally generated missiles with penetrating power approaching the design basis missile was possible.

3. For the equipment not isolated by missile proof walls (targets), possible sources of internally generated missiles were postulated. The source missiles were evaluated with respect to weight, impact areas and kinetic energy. Table 5.2-15 gives the postulated missiles for each target. In order to minimize repetitive calculations, the source missiles are typical and kinetic energy data for each type missile represents the maximum possible for that type. For example, on motor couplings, the heaviest weight, smallest size, highest torque and speed were selected and these parameters were used for establishing kinetic energy and impact area of a design missile coupling. These design missile-types represent a conservative, maximum value for missile parameters.

The missile with the highest kinetic energy-to-impact area ratio (KE/A), which is considered the most destructive missile, is a propane bottle relief device (Type 3) with KE/A of 7656 ft-lb per square inch. The KE/A of 9195 ft-lb per square inch for the design basis missile compared to the maximum KE/A from Table 5.2-15 justifies the "exclusion from further analysis" approach of the safety related equipment isolated by missile proof walls.

5.2.6.2 Exterior Missiles

The containment has not been analyzed for exterior missiles generated by hypothetical aircraft accidents, due to the site being located more than 5 miles from any airport (Table 2.1-7).

Tornado generated missiles discussed in Section 2.7 include one potential missile equivalent to a 35-ft long wooden utility pole impacting at a velocity of 150 mph.

5.2.6.3 Criteria for Protection Against Dynamic Effects Associated with a Major Pipe Rupture

The containment vessel and all essential equipment within the containment are adequately protected against the effects of blowdown jet forces and pipe whip resulting from a postulated pipe rupture of main steam, and feedwater (Class 2) lines. The criteria for adequate protection permits limited damage when analysis or experiment demonstrates that:

1. Leakage through the containment will not cause offsite dose consequences in excess of 10CFR part 100 guidelines.

2. The minimum performance capabilities of the engineered safety systems are not reduced below that required to protect against the postulated break.

3. A pipe break which is not a loss of reactor coolant will not cause a loss of reactor coolant or steam or feedwater line break. Also, a reactor coolant system pipe break will not cause a steam-feedwater system pipe break and vice versa.

This level of protection is assured by adherence to the following design criteria.

<u>Placement of Piping and Components</u>

The routing of pipe and the placement of components minimize the possibility of damage.

The polar crane wall serves as a barrier between the reactor coolant loops and the containment liner. In addition, the

refueling cavity walls, various structural beams, the operating floor, and the crane wall, enclose each reactor coolant loop into a separate compartment, thereby preventing an accident, which may occur in any loop, from affecting another loop or the containment liner. The portion of the steam and feedwater lines within the containment have been routed behind barriers which separate these lines from all reactor coolant piping. The barriers described above will withstand loadings caused by jet forces and pipe whip impact forces.

Other than for the Emergency Core Cooling System lines, which must circulate cooling water to the vessel, the engineered safety features are located outside of the crane wall. The Emergency Core Cooling System lines are routed outside of the crane wall so that the penetrations are in the vicinity of the loop to which they are attached.

Supplemental Protection

In those regions where the careful layout of piping and components cannot offer adequate protection against the dynamic effects associated with a postulated pipe rupture, restraints to prevent excessive pipe movement or special shielding is provided.

The careful layout of piping and components offers adequate protection against the dynamic effects associated with a postulated pipe rupture except in the case of the main steam and feedwater lines outside the crane wall.

The basis for selecting break locations in the main steam and feedwater systems, whose piping is similar to ASME Boiler and Pressure Vessel Code, Section III, Class 2 piping, is discussed below and is consistent with Regulatory Guide 1.46 "Protection Against Pipe Whip Inside Containment."

Since the probability of rupture is strongly related to stress, only a limited number of break locations are postulated. Supplemental protection is provided on the main steam and feedwater lines for breaks at locations described below:

1. At the two terminal points

2. At the point of maximum primary plus secondary stress

3. At any other point where the primary plus secondary stress exceeds 80 percent of its allowable; i.e., 0.8 $(S_A + S_h)$.

The main steam and feedwater piping (similar to ASME Boiler and Pressure Vessel Code III, Class 2 piping) requires pipe break restraints in order to protect the integrity of the containment lines. There are six piping runs. Each run contains a total of three or more postulated break points.

Table 5.2-16 gives the pipe break locations postulated for the three main steam and three main feedwater pipe runs inside the containment building. The loop A main steam line contains three break points and/or areas. Restraint locations are based upon what were, at the time of design fixing, the prevailing criteria for number and type of break.

Restraints offer good supplemental protection since pipe displacements are minimized and large kinetic energies are prevented.

The placement of the restraints will prevent excessive pipe displacements in the event of either a longitudinal split or circumferential break, or both, depending on the state of stress in the line.

In the area where the feedwater and the main steam piping penetrate the containment shell, the liner is also protected by an overlay of 1 1/2 inch thick quenched and tempered steel plate.

Methods of Analysis

Analyses are performed for pipe impact and jet impingement. In addition, major equipment supports are analyzed to ensure adequacy under postulated pipe rupture loads transmitted by attached piping.

For the purposes of design, unless otherwise stated, the pipe break event is considered a faulted condition, and the pipe, its restraint or barrier, and the structure to which it is attached are designed accordingly.

Restraints which require plastic deformation are based on 50 percent of ultimate strain.

The forces associated with both longitudinal and circumferential ruptures are considered in the design of supports and restraints in order to ensure continued integrity of vital components and engineered safety features.

The break area for both postulated break types is the cross-sectional area of the pipe. The break length for the postulated longitudinal breaks is assumed to be equal to twice the pipe diameter.

The analysis takes advantage of limiting factors on the blowdown thrust force, such as line friction, flow restrictors, pipe configuration, etc. A rise time is applied to the thrust force to simulate the crack opening time. A one millisecond rise time is assumed for circumferential breaks. For longitudinal splits, a rise time is computed based on the growth of a crack from a critical length to a length of two pipe diameters at a propagation rate of 500 ft/second.

Pipe Restraints

The restraints are designed with a gap sufficient to prevent interference with the normal thermal dynamic motion of the lines. This permits the pipe to acquire kinetic energy which must be dissipated upon impact into the restraint. This energy was conservatively set equal to the product of peak thrust times displacement. No energy dissipation mechanisms operating prior to impact, such as plastic deformation in the pipe, were considered. Static analyses of the deformation of the restraints and bolts provided the force displacements characteristics of the restraints. The area (energy) under this force-displacement curve was matched to the kinetic energy of the impacting pipe to determine the deformation and load. Based on recent, more detailed analyses, the conservatism of this design approach has been proven.

The restraints consist of a circular arch (or yoke) and a welded base support structure that is bolted to a supporting wall. These restraints are designed so that, by the use of self-adjusting shims, the gap between the pipe and the inner surface of the restraint is kept as small as practicable while still allowing free thermal expansion of the pipe during plant operation.

The barrier provided near the containment penetration is attached to the pipe penetration sleeve.

Equipment Supports

The internal structural system of the containment is designed to mitigate loading due to rupture in the main reactor coolant lines and the main steam and feedwater lines. Incident rupture is considered in only one line at a time. The support system is designed to preclude damage to or rupture of any of the other lines as a result of the incident. The snubber and key systems are designed to deliver rupture thrusts on the steam generator into the internal structural system. In determining the steam generator support reactions, the system is reduced to a dynamic model consisting of a suitable nuclear of masses and resistance elements. The dynamic problem is solved by numerical methods, using a thrust time history as loading. Resistance, dynamic amplification of the thrust, and rebound forces are calculated as a function of time. The reactor vessel and support system is similarly treated.

5.2.6.4 Pipe Whip Analysis

The analysis of the restrained piping within the containment was completed and the fabrication of restraints begun before any officially acceptable criteria for analysis was published. Subsequent to the completion of the analysis, analytical methods and criteria to be used in determining pipe whip analysis was transmitted to BVPS from the AEC. The analytical methods and criteria are provided in Attachment A to Section 5.2, "Pipe Whip Analysis Guidelines". The analytical methods and criteria used were similar to, but not identical with, those outlined in Attachment A. To facilitate a comparison, the original criteria is provided in Attachment B using the format of Attachment A and a point-by-point comparison is presented. Emphasis is placed on those criteria which differ.

5.2.7 Corrosion Protection and Coatings

5.2.7.1 Steel Liner

The exterior of the steel liner is not coated because it is in intimate contact with the concrete and has adequate protection from corrosion. The interior of the steel liner has an inorganic zinc coating with a white epoxy topcoating which provides protection for both normal operating and accident conditions.

5.2.7.2 Concrete and Structural Steel

All interior concrete and structural steel surfaces in the containment structure were given a coating suitable for service under DBA conditions. The steel floor grating is galvanized.

The coating system used on the preponderance of carbon steel surfaces within the reactor containment consists of a zinc-rich inorganic vehicle primer, topcoated with one or more coats of polyamide epoxy. Some items of equipment and certain other items, with relatively small amount of surface area, were coated with a straight organic system. Concrete surfaces are coated with at least two coats of polyamide epoxy.

The criterion for the selection of the above coating systems was the performance of these systems when subjected to tests simulating the environment anticipated within the containment in the event of a DBA. The coating systems indicated have demonstrated the ability to retain their integrity under DBA conditions, similar to those described in Section 7, in such a way as to ensure that the coating systems used will not compromise the efficiency of the safety systems.

The DBA simulation tests conducted for the purpose of validating the acceptability of the coating systems used were, for the most part, conducted in accordance with Section 4, "Procedures for Testing Coatings at Simulated DBA Conditions" of American National Standards ANSI N101.2.[42]

3. The restraints, as designed, have a large margin of safety since the permissible limits on strain have not been approached.

c. No rise time was applied to the forcing function. This is in accordance with Attachment A.

d. Transient functions were not used so this criteria is not applicable.

e. The jet thrust force was considered as a steady state function (part b, above). The justifications are:

1. During the period during which impact phenomena occur, the jet thrust is either steady or drops.

2. The energy balance model was used. Justification is provided for not using an amplification factor. This is in accordance with II.a(2) of Attachment A.

3. Not applicable.

III. Sample Problem

The original analyses of the main steam and feedwater pipe whip restraints inside the containment were based on the energy balance method. The results of those analyses indicated that the restraint which would be most highly deformed as a result of pipe impact was attached to the top of the crane wall near an elbow in a main steam line. The analytical method and results for this restraint are provided in Section III.A. A new analysis, using a lumped-parameter analysis model and conforming to Attachment A, is also presented to prove that this "worst case" restraint is satisfactory when analyzed to the new criteria.

The physical arrangement of the restraint and pipe is shown in Figure 5.2-54. For a circumferential break at one end of the elbow, the pipe is thrust against the restraint, pulling it away from its embedment. A one-inch gap between the pipe and restraint is assured by the placement of shims while the pipe is in the hot position.

III.A Energy Balance Model (Original Method)

The pipe-restraint interaction was analyzed using an energy balance method in which the work done by the blowdown thrust was equated to the strain energy of the deformed restraint. The solution provided the peak reaction load in the restraint and the strains in the component parts of the restraint.

The work done by the blowdown thrust is the product of force times distance. As described in Section III.B:

$$E_i = F \bullet (g+x) \qquad (5.2B-4)$$

where: E_i = Energy input

F = Blowdown Thrust

g = pipe restraint gap

x = restraint deflection at impact point.

Section II.D gives for the blowdown thrust:

$$F = p_o A \qquad (5.2B-5)$$

where: p_o = design pressure

$A = \pi r_i^2$ = break area

Thus: $$E_i = \pi p_o r_i^2 \ (g+x) \qquad (5.2B-6)$$

This is shown in Figure 5.2-55 for several gap dimensions. Since shims were used to ensure a one-inch gap between the restraint and the pipe in the hot position, only one of these curves is applicable to the actual design.

The basis for the energy absorption characteristics of the restraint was a multi-stage static stress analysis. The force-deflection properties of the restraint were determined using a mathematical model. Initially, all members were considered elastic, and a load was applied in the radially outward direction. The first region to yield was the arch structure at the point of load application. The restraining structure remained fully elastic up to 900 kips.

At yield, the mathematical model was modified by placing a pin at the node where the plastic hinge had formed. A moment, corresponding to the fully plastic moment across this section, was applied across the pin. This moment remained constant throughout the remaining analysis, so strain hardening was not considered. The load applied to this model was gradually increased until the bolts holding the restraint to the embedment yielded at 1300 kips.

The mathematical model was again modified to reflect the plastic properties of these long stainless steel bolts. For the bolts, which deform in simple tension, strain hardening was considered. These are the only components in which strain hardening was considered during the analysis of all the restraints.

1. Safety Injection Pump Discharge (Penetration Nos. 7, 33, 60, 61, 62, 96, and 113)

The safety injection system (Section 6.3) must be operated after a DBA to keep the reactor core covered with water following the accident (refer to Figure 6.3-8 for a diagram of the following valve arrangements). The boron injection (high head safety injection to reactor coolant cold legs) containment isolation valves are designed to be opened upon receipt of a safety injection signal. The remote manual valve affecting containment isolation in the low head safety injection header to the reactor coolant cold legs is normally open and remains open during the accident. The other valves affecting high head safety injection headers and in the low head safety injection headers to the reactor coolant hot legs are administratively controlled closed.

The high head safety injection lines to the reactor coolant hot legs and the high head safety injection line to the reactor coolant cold legs are each provided with a normally closed, remotely controlled, motor-operated isolation valve located outside the containment, and a check valve inside the containment.

The boron injection line (high head safety injection to cold legs) is provided with two normally closed, remotely controlled, motor-operated isolation valves located in parallel in the line outside the containment and a check valve inside the containment.

Two of the low head safety injection penetrations are provided with check valves inside the containment in the lines leading to the reactor coolant hot legs. These valves are located downstream of the point at which the two lines form a common header and split into three lines, but upstream of the point where the three lines connect to the high head safety injection line to each of the reactor coolant hot legs. The third low head safety injection line penetrating the containment branches into three lines leading to the reactor coolant cold legs, each of which is provided with a check valve inside containment. These valves are located upstream of the point at which each line connects to the high head safety injection line to each of the reactor coolant cold legs. Outside the containment, the three low head safety injection lines are connected to the discharge lines from the two low head safety injection pumps. The two discharge lines leading to the reactor coolant hot legs are provided

with normally closed, remotely controlled, motor-operated isolation valves. The discharge line leading to the reactor coolant cold legs is provided with a normally open, remotely controlled, motor-operated isolation valve. Before the refueling water storage tank (RWST) is empty following a DBA, valves in the low head safety injection (LHSI) system are closed to isolate the RWST from the containment. The safety injection pump discharge conforms to the intent of General Design Criterion 55. The only difference being the isolation valves located outside containment are opened during containment isolation either automatically or administratively to perform a post DBA safety injection and containment depressurization function.

These containment isolation arrangements conform with the design bases specified in Section 5.3.1, and also allow the safety injection system to perform its designed post DBA function.

2. Low Head Safety Injection Pumps and Outside Recirculation Spray Pumps Suction Lines (Penetration 66, 67, 68, and 69)

The suction lines for the low head safety injection pumps and the recirculation spray pumps are very conservatively designed to prevent gross system leakage. The major portion of this special class piping is buried in the reinforced concrete base mat and only a short length of piping exists between the mat and the isolation valves.

The motor-operated isolation valves (one in each line) at the suction of the outside recirculation spray pumps are normally open and remotely controlled. The motor-operated isolation valves (one in each line) for the low head safety injection pump suction lines are normally closed and remotely controlled. The remote operators used for these valves are designed to be highly reliable.

Assuming the worst possible single passive failure occurs to any suction line, as postulated in Section 1.3.1, the safeguards area suction valve pit becomes flooded. This provides a water seal between the containment and the outside atmosphere which prevents leakage into or out of the containment.

the rupture of the AFW system is not postulated to occur either concurrent with or as a result of a loss-of-coolant accident (LOCA). Additionally, a similar AFW system configuration was approved by the Staff for the North Anna Power Station, Units Nos. 1 and 2, on the same bases.

The containment isolation features described above are sufficient to achieve the underlying purpose of GDC 57.

10. Recirculation Spray Heat Exchanger River Water Radiation Monitor Sample Lines (Penetrations 83, 84, 85 and 86)

Radiation monitor sample lines are provided to sample each river water line at a location down stream of the recirculation spray heat exchangers, outside containment, and upstream of the containment isolation valve for the river water line. The radiation monitor sample lines are normally open and remain open (unisolated) following a design basis accident to allow rapid detection and isolation of any radioactive releases resulting from a recirculation spray heat exchanger tube leak.

In the event radioactive leakage is detected, the radiation monitor and associated high radiation alarm would provide indication of a recirculation spray heat exchanger tube leak, and alert the operator to take corrective action. Manual valves at the radiation monitor skids are accessible for local isolation of a sample line during accident conditions.

The use of locked-closed valves to isolate the sample lines would delay isolating a radioactive release due to a leaking recirculation spray heat exchanger tube, and the use of local manual valves will not result in a significant increase in the total offsite radioactivity release. In addition, the use of automatic or remote-manual valves would result in undue cost in comparison to the safety benefit to be derived. Thus, application of GDC 57 in this instance is not necessary to achieve its underlying purpose.

Shortly after a DBA, the ambient temperature within the containment may be as high as 280°F. Although such high temperatures are short lived (the containment is reduced to subatmospheric conditions in less than 60 minutes as the containment depressurization system, Section 6.4, cools the containment atmosphere), it is possible that water trapped in the lines of the systems isolated by the containment isolation system

may expand more rapidly than the associated piping. This could result in pressures exceeding the design pressure of the piping. To ensure that such overpressurization of isolated piping cannot adversely affect containment isolation integrity, a relief valve set to relieve at a pressure at or below the design pressure of the associated piping is installed in the few affected lines inside the containment between the containment wall and the inside isolation valve. These relief valves are designed to reseat when overpressure conditions subside.

Weight and spring loaded check valves used for containment isolation are designed to require, in order to open, a differential pressure across the valve in the normal flow direction exceeding the expected post DBA differential pressure between atmosphere and containment (about 1.2 psi). As a result, leakage into the containment through incoming lines with check valves inside the containment caused by passive failures of such lines between the containment penetration and the outside isolation valve is prevented. The use of spring and weight loaded check valves inside the containment on outgoing lines ensures positive seating of such valves after the containment has been returned to subatmospheric pressure following a DBA.

5.3.4 Containment Isolation Valves

The containment isolation system conforms to Appendix A of 10 CFR 50, General Design Criteria for Nuclear Power Plants, Criteria 55 through 57, as modified by Section 5.3. Valve design and application details are provided in Table 5.3-1. The valves supplied by Stone & Webster were analyzed for stresses due to operating and seismic loads as discussed in Appendix B.2.2. The analysis of the Westinghouse supplied valves is discussed in Appendix B.3.

Containment isolation trip valves are designed to be operable under normal operating environmental conditions during the life of the plant and during seismic conditions. Those with a solenoid or air operator are designed to trip shut at the onset of a DBA and remain closed during post accident environmental conditions. Those valves with a motor operator are designed to "fail as is" at the onset of a DBA.

To ensure reliability, containment isolation motor-operated and trip valves were designed and procured to meet the minimum design requirements for containment isolation valves as specified in American National Standards Institute, ANSI B31.1, 1967[3], ANSI B16.5[4], and Manufacturers Standardization Society Standard Practice, MSS-SP-66[5], with additional nondestructive testing of pumps and valves in accordance with ASME Boiler and Pressure Vessel Code (Draft issue) dated November 1968. The selection of valve operators and types was made on the basis of past experience and best practices.

To ensure safe and reliable system operation, the following design features have been incorporated into the Containment Isolation Valves.

1. The design pressure of all the isolation valves are in excess of the containment design pressure.

2. Check valves, when used as containment isolation valves, are loaded to close against a 2 psi positive differential pressure.

3. Circuits which control redundant automatic valves are redundant to the extent that no single failure will preclude isolation.

4. The closure time for valves in the pipelines, which might have the potential of releasing radioactive elements to the atmosphere, have been limited to as small a period as possible consistent with the design of valves and operators.

Gate valves are used extensively for remote operated containment isolation valves because of their tight seating characteristics, essential deep stuffing box features for handling radioactive fluid, and availability in a larger size of pressure ratings and sizes.

Butterfly containment isolation valves are selected in lieu of gate valves in certain applications for their use in low pressure, large line sizes.

Globe valves are used exclusively on closed conduit systems as the type of containment isolation trip valves because of the short stem travel, and therefore, quick closing capability. This requirement ensures integrity of containment isolation to limit release of radioactivity to the environment. These valves provide overpressure relief protection by opening due to liquid pressure buildup under the seat as a result of transient temperature conditions following a DBA. External relief is not required unless the relief pathway can be isolated. In such cases, a relief valve is installed between the isolation valves. Refer to Table 5.1-1 of the Licensing Requirements Manual for the description of containment penetration relief protection requirements. In addition to the code requirements, additional quality assurance and test programs were imposed on these valves to achieve optimum reliability.

Based on previous successful operating experiences of Limitorque operators in other nuclear plants, Limitorque motor operators have been accepted for BVPS-1. These operators are used extensively in nuclear applications. Limitorque operators are designed to be operable during the life of the plant and are tested to operate during DBA conditions. Motor operators supplied by Limitorque conformed to all applicable National Electrical Manufacturers Association (NEMA) and Institute of Electrical and Electronic Engineers (IEEE) Standards and were tested to NEMA MG-1-10.35[11]. Motor operators were tested in accordance with IEEE Std. 382,[12] to demonstrate satisfactory operation in the combined pressure, temperature, atmospheric and radiation conditions. These tests were conducted by Franklin Institute Research Laboratories and are documented in their final report[13].

In order to ensure the operability of motor-operated valves, manufacturers have performed the operability test in a dry condition in their plant, have certified that valve and motor operator will withstand the specified environmental conditions and have submitted a static seismic analysis which was approved by Stone & Webster.

Prior to their installation in the plant, motor-operated isolation valve bodies were hydrostatically tested at a pressure equal to twice the nominal pressure rating, with a test duration of 10 minutes for valves with minimum wall thickness up to and including 1 inch and 30 minutes for valves with larger wall thicknesses. Motor-operated valves were tested for seat tightness at the nominal pressure rating of the valve for not less than 5 minutes. The permissible seat leakages were in accordance with MSS-SP.61.[6]

Valves listed below were subjected to special preoperational testing requirements:

1. MOV-RS-156A and MOV-RS-156B in the recirculation spray system were subjected to zero seat leakage and backseat tests.

2. Weight loaded check valves QS-3, QS-4, RS-100 and RS-101 in quench spray and recirculation spray systems were subjected to seat tightness test in accordance with MSS-SP61 with differential pressure of 9 to 45 psi in the reverse flow direction and 2 psi in normal flow direction.

3. MOV-FW-156A, MOV-FW-156B, and MOV-FW-156C - motor-operated check valves in the main feedwater system were designed to seal against 5.5 psi pressure differential in the normal flow direction.

4. Ventilation isolation valve (dampers), which serves as containment isolation, were subjected to the following tests:

   a. Shell test - valves were tested at 70 psig for a period of at least 10 minutes (during which there was no leakage allowed)

   b. Seat test - the valves were air tested under water at 70 psig for a period of 15 minutes, during which time there was no visible leakage

   c. Steam test - the valves were steam tested at 45 psig saturated for 30 minutes during which time there was no leakage through any part of the valve allowed.

All parts of containment isolation trip valves, subject to line pressure were tested both for mechanical functioning and tightness of the valve seat and shell. Hydrostatic test pressures were equal to or greater than required by ANSI B16.5 and MSS-SP-61 for the conditions of service. In addition to hydrostatic tests, maximum operating pressure backseat leakage was less than 5×10^{-4} cubic centimeters per minute per PSI differential pressure per inch of port diameter. Maximum leakage below valve seats was limited to 6×10^{-7} standard cubic centimeters per second per inch of valve diameter.

All containment isolation valve radiographic examination was in accordance with American Society for Testing Materials ASTM Specifications E-94[7] and E-142[8].

In addition to radiographic examination requirements, magnetic particle inspection on ferrous isolation valves was performed in accordance with ASTM E-709,[9] previously ASTM E-109, and stainless steel isolation valves were liquid penetrant inspected in accordance with ASTM E-165.[10]

References for Section 5.3

1. Letter from Stephen H. Hanauer, Chairman, Advisory Committee on Reactor Safeguards, to Honorable Glenn T. Seaborg, Chairman, USAEC, dated May 15, 1969, subject: "Report on Edwin I. Hatch Nuclear Plant."

2. Letter from Stephen H. Hanauer, Chairman, Advisory Committee on Reactor Safeguards, to Honorable Glenn T. Seaborg, Chairman, USAEC, dated May 15, 1969, subject: "Report on Brunswick Steam Electric Plant."

3. "Power Piping Code," ANSI Std. B31.1-1967, The American National Standards Institute.

4. "Steel Pipe Flanges, Flanged Valves and Fittings," ANSI Std. B16.5, The American National Standards Institute.

5. "Pressure-Temperature Ratings for Steel Butt-Welding End Valves," MSS-SP-66, The Manufacturers Standardization Society Standard Practice.

6. "Hydrostatic Testing of Steel Valves," MSS-SP-61, The Manufacturers Standardization Society Standard Practice.

7. "Recommended Practice for Radiographic Testing," ASTM E-94, The American Society for Testing Materials.

8. "Controlling Quality of Radiographic Testing," ASTM E-142, The American Society for Testing Materials.

9. "Practice for Magnetic Particle Examination," ASTM E-709, The American Society for Testing Materials.

10. "Liquid Penetrant Inspection Method," ASTM E-165, The American Society for Testing Materials.

11. "Motors and Generators," NEMA MG-1, The National Electrical Manufacturers Association.

12. "Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations," IEEE Std. 382, The Institute of Electrical and Electronic Engineers, Inc.

13. "Qualification Test of Limitorque Valve Operation, Motor Brake, and Other Unit in a Simulated Reactor Containment Post-Accident Environment," F-C3327, Franklin Institute Research Laboratories.

14. "American Standard for Industrial Control Apparatus," C19.1, The American National Standards Institute.

References for Section 5.3 (Cont'd)

15. Branch Technical Position MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment from NUREG-0800, Section 3.6.2 titled Determination of Rupture Locations and Dynamic Effects Associated with Postulated Rupture of Piping, Rev. 1, July 1981.

16. NERU Calculation No. 8700-46.4-1 and 8700.46.7

17. Technical Specification Change Request No. 130

5.4 INTERNAL CONTAINMENT SYSTEMS

5.4.1 Ventilation Systems

The containment ventilation systems consist of containment air recirculation cooling systems, control rod drive mechanism shroud cooling systems, containment iodine filtration systems and a containment purge exhaust and supply system, as shown in Figures 5.4-1 and 5.4-2.

5.4.1.1 Design Bases

The containment ventilation systems and air quantities are designed and sized to limit ambient air temperature buildup and to provide suitable environment for personnel and equipment with maximum safety against the spread of radioactive contamination.

The design of the air recirculation cooling system is based on a total air flow rate of 450,000 cfm with three fan operation. The design of the control rod drive mechanism shroud cooling system is based on an air flow rate of 66,000 cfm with two fan operation.

The air recirculation cooling system is designed so that under full power operation with one unit out of operation, the maximum average temperature will be limited to 105°F within the containment with cooling water at 70°F.

In the event of the loss of all normal onsite and offsite power, the containment average temperature should not exceed 135°F. This temperature limit is established to prevent the damage of instrumentation within the containment which would prevent the plant from being returned to operation once normal power was restored. In the event of loss of all normal onsite and offsite power, when the emergency busses are loaded on the emergency diesel generator (EDG), the containment air recirculation fans do not start on the load sequencer and will not be loaded manually on the EDG.

Normally water is supplied to the cooling coils from the chilled water system at 45°F. An alternate source of water is also provided by piping from each river water header. Component cooling water is supplied to the cooling coils of the control rod drive mechanism shroud cooling system.

The air recirculation cooling systems, control rod drive mechanism shroud cooling systems and iodine filtration systems are designed to operate in both subatmospheric and atmospheric conditions.

No part of the containment ventilation systems is designed for operation during a DBA.

A nominal flow of 2,000 cfm is the design basis for the separate iodine filtration system with impregnated charcoal cells sized for 500 cfm and minimum charcoal composite efficiency of 95 percent based on the influent iodine composed of 90 percent elemental and 10 percent organic iodines.

Purge exhaust is designed in the normal mode for a one air change flow rate of 30,000 cfm with connections to supplemental leak collection and release filter banks and duct system dampers arranged to reduce the concentration of any possible airborne radioactivity to levels acceptable for atmospheric discharge at an elevated release point meeting the requirements of 10 CFR 20 and 10 CFR 50. During containment refueling activities, the air flow rate is 7,500 cfm and the purge exhaust is lined up to the supplementary leak collection and release system through seismically designed ducts and dampers. The purge exhaust system is also designed with radiological monitoring to meet the requirements of 10 CFR 20 and 10 CFR 50. The purge exhaust is designed with the capability of diverting a reduced flow rate of 1,000 cfm to the process vent filters and gaseous waste blowers discharging at the top of the cooling tower in the event of a high degree of activity.

The common ventilation vent, located on top of the auxiliary building is designed to discharge low level and nonradioactive purge exhaust air at a point 10 ft higher than the turbine building roof.

Purge supply is designed for a flow rate of 27,000 cfm which is less than the normal exhaust rate to maintain a slight negative pressure in the containment. During containment refueling, air infiltrates into the containment through the purge supply system.

Reactor coolant pump motors do not constitute a major heat source since they are cooled by self-contained water coils fixed to the motor housings.

5.4.1.2 Description

Bulk air cooling of the containment is achieved by three air recirculation cooling systems with the recirculated air being cooled on passing through chilled water or river water coil banks. Cooled air is circulated by three 50 percent design capacity fans, each with a capacity of 150,000 cfm, discharging into common ductwork supplying the ventilated spaces. Air leaving the ventilated spaces is recirculated back to the supply fans via the annular space between the crane wall and containment outside wall. All three fans are normally operable; however, bulk air temperature is limited to a design maximum of 105°F with any two fans in operation. Gravity actuated back draft dampers are installed at the discharge of each fan to prevent reverse flow through an idle fan.

Alarms are provided in the main control room to indicate that the containment pressure has dropped below the normal operating band which is ±0.1 psi of the setpoint. This allows sufficient time for the operator to take corrective action before the pressure drops below the design loading of the containment. Administrative procedures require that the steam ejector be separated from the containment atmosphere by normally closed, manual, administratively controlled valves to prevent its operation at any time other than that required during startup of the unit.

If the steam ejector is operated for an extended period of time in violation of the operating procedures and alarms, it is unlikely that a vacuum beyond the design loading of the containment will be reached. The containment is designed to withstand a pressure of 8.0 psia. Assuming that the containment pressure is at the normal operating pressure of 9.5 psia, it would take approximately six additional hours to reduce the pressure to 8.5 psia, which is above the design pressure. The efficiency of the steam ejector is very low at pressures below 9.5 psia; thus, it requires a long period of time to effect a small reduction in pressure. The steam ejector is not designed for operation below 9.0 psia, and performance below this value is significantly degraded. Therefore, to reach the design value of 8.0 psia it would be necessary to operate the steam ejector in excess of six hours after normal operating pressure is established. Continued operation of the ejector after establishment of the operating pressure is not considered credible because of the controls previously discussed. Therefore, a containment vacuum breaker is not required to prevent depressurization below the design loading of the containment.

The minimum pressure to which the containment might be expected to be depressurized, assuming inadvertent operation of the steam ejector, is 0.1 psi below the containment vacuum system setpoint established by the Technical Specifications. Assuming the lowest expected setpoint of 9.0 psia and based on the alarm setpoint, the lowest pressure in the containment would be 8.9 psia.

Based upon the operating experience at the Surry Nuclear Station where two reactors which utilize subatmospheric containment are presently operating it is anticipated that containment entry may be made at all times during normal power operation, during hot shutdown or at any time while placing the plant in a cold shutdown condition.

Tests and Inspections

The containment vacuum ejector is not considered a part of the engineered safety features and, since it is such a simple mechanical device, periodic tests are not required. The mechanical containment vacuum pumps are operated during the initial containment leakage rate test (Section 5.5) and demonstrated to have adequate capacity to remove inleakage. During normal unit operation, they are alternated in service, thus providing periodic testing of each containment vacuum pump.

5.4.2.2. Containment Leakage Monitoring System

Design Bases

The containment leakage monitoring system is used to determine the leakage rate of the containment under periodic test conditions. The containment leakage rate is determined using the absolute test method, and either the Mass Point or Total Time data analysis method is used to calculate the containment leakage rate.

The system provides for measurement of containment leakage rate of less than 0.1 percent of the contained volume in 24 hours with an accuracy sufficient to meet the requirements of Appendix J, 10 CFR 50. The system is designed in accordance with ANSI N45.4, American National Standard, Leakage Rate Testing of Containment Structures for Nuclear Reactors, March 17, 1972. Containment leakage rate testing is conducted in accordance with 10 CFR 50, Appendix J with certain exceptions as noted in the Technical Specifications.

5.5 DESIGN EVALUATION

The reactor containment concept is based upon the use of a dry containment maintained at a subatmospheric pressure during normal operation. Pressure limitations allow restricted personnel access to the containment. Following a Design Basis Accident (MSLB), the containment pressure rises above atmospheric to a maximum possible peak of 44.2 psig, with subsequent outleakage.

Through the use of the containment depressurization system (Section 6.4), the containment returns to subatmospheric pressure within 60 minutes after initiation of a DBA (LOCA or MSLB), thus terminating outleakage from the containment. The amount of activity released to the environment as a result of a DBA is much less than would be released from an atmospheric containment, thereby reducing the size of the required exclusion area and the low population zone as defined and determined by 10 CFR 100. The population center distance requirement is correspondingly reduced below that required for an atmospheric containment (Section 2.1).

The containment depressurization system is considered to be an engineered safety features system. The containment vacuum system (Section 5.4.2) is not considered to be an engineered safety features system.

Containment isolation features, such as penetrations, access hatches, and isolation valves, meet the requirements of 10 CFR 50 Appendix A (Section 1.3 and Appendix 1A).

The containment structural design is in accordance with the best current design practices for steel lined reinforced concrete reactor containment structures. The design procedures incorporate accepted analytical methods. Rigid controls were maintained for all materials and construction practices as indicated in Section 5.2 and 10 CFR 50 Appendix A. The proposed subatmospheric pressure operation results in no significant effect on the structural design.

The environmental conditions (atmospheric pressure, temperature, and humidity) inside and outside the containment structure were continuously monitored during the test to evaluate their contribution to the response of the containment. The test was not conducted under extreme weather conditions such as snow, heavy rain, or strong wind.

When the containment structure was subjected to the peak test internal pressure, the maximum radial growth was expected to be approximately three-quarters inch and the maximum vertical deformation at the dome apex to be approximately one and one-half inch. These deformations were calculated for the analytical stress evaluation of the containment liner. Strain measurements were made on the steel liner using conventional strain gages at adequately selected points.

During the acceptance test, visual examination and instrumentation were used to record cracking and changes in measurements, both vertically and radially, due to the response of the concrete containment structure to the air pressure test of the liner. Prior to testing, the outside of the concrete structure was surveyed, measured, and inspected for cracks, and all pertinent information recorded. During the test, measurements were made of the radial deflections at various locations on the wall from the top of the mat to the spring line of the dome. Two permanent pits located approximately 90 degrees apart were provided for access to the containment wall below ground grade. These pits allowed localized visual inspection and measurements of the lower part of the wall.

Vertical deflections were measured at the apex and spring line of the dome. Additional strain measurements were made on the surface areas adjacent to the equipment access hatch and in other areas where stresses were critical.

Deformations were measured by linear variable differential transducers (LVDT's) mounted at the internal surface of the liner plate. LVDT's were also used to measure displacements of the concrete ring around the equipment hatch. Cracks larger than 0.01 inch which occur during the test were recorded. They were measured by an optical comparator and checked with feeler gages. After the completion of the test recovery of the structure was recorded. The crack pattern was again inspected and recorded.

The containment concrete surface was whitewashed in areas of high stress and at openings to chart crack patterns. Photographs were taken of the crack patterns to provide permanent records.

Temperature, barometric pressure and weather conditions were recorded hourly during the test period.

Containment Leakage Rate Tests

The containment leakage rate tests are performed in accordance with the guidelines of Appendix J of 10CFR50, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

The containment leakage testing program includes the performance of Type A tests, to measure the containment overall integrated leakage rate, Type B tests, to measure leakage of certain containment components, and Type C tests, to measure containment isolation valve leakage rate. The calculated MSLB peak containment pressure is 44.2 psig; however, containment leakage rate tests are based upon the limiting radionuclide releases due to a LOCA.

The preoperational Type A test was conducted according to the rules of Appendix J, Option A.

Periodic Type A tests are conducted in accordance with Appendix J, Option B (with the exemption noted in the Technical Specifications). These tests are performed using the leakage monitoring system (described in Section 5.4.2.2).

The measured leakage rate does not exceed the design basis accident leakage rate (La) of 0.1 percent per 24 hours of the weight of containment air at the calculated LOCA peak containment pressure of 40.0 psig. The remaining leakage characteristics are determined in accordance with Appendix J, Option B as documented in the Containment Leakage Rate Testing Program (CLRTP).

Type B tests are carried out to monitor the principal sources of leak development in accordance with Appendix J. These tests are performed to measure leakage originating at containment penetrations, such as electrical penetrations, air lock door seals, and equipment and personnel access hatches, which may develop leaks. Refer to the CLRTP for more information regarding the containment components to be tested.

The preoperational Type B tests were conducted according to the rules of Appendix J, Option A by local pneumatic pressurization of the containment components at a pressure not less than Pa.

Periodic Type B tests are conducted in accordance with Appendix J, Option B as documented in the CLRTP. The acceptance criterion for periodic Type B tests is given in the CLRTP.

The periodic Type B tests are scheduled according to the guidelines of the CLRTP.

The Type C tests are performed on the isolation valves to verify their sealing capability and leak-tightness according to Appendix J. The test includes valve closure and leakage tests. A valve closure test is conducted prior to a valve leakage test to demonstrate the proper sealing capability of a valve upon receipt of an isolation signal. Those isolation valves which are normally closed are exercised to verify closure and sealing capabilities. Those containment isolation valves which are in a system that is expected to be filled with water for 30 days following a LOCA and therefore do not represent a containment atmosphere leak path are not subject to the Type C test requirements of 10CFR50 Appendix J.[1]

The preoperational Type C tests were conducted according to the guidelines of Appendix J, Option A by local pneumatic pressurization at a pressure Pa.

The periodic Type C tests are conducted according to the guidelines of Appendix J, Option B as documented in the CLRTP.

The structural integrity of the containment will be determined during the shutdown for each Type A containment leakage rate test in accordance with the CLRTP.

Licensing Requirements Manual Table 5.1-1, "Containment Penetrations" lists the containment isolation valves which can be individually leak tested.

References to Section 5.6

1. Amendment No. 65 to Technical Specification 4.6.1.2d and Table 3.6-1

TABLE 5.2-15

INTERNAL MISSILE SUMMARY

Missile Source	Missile (See Notes)	Actual Weight (lb)	Actual Impact Area (in.^{2})	Speed Torque or Pressure	Targets	Type KE (ft-lb)	Type KE/A (ft-lb/in.^{2})
Fuel Pool Purification Pump	Type 1B (1 x 1 x 2)	0.58	1.0	Diam of coupling 6" at 1,750 rpm spider coupling	Fuel Pool Cooling HX and Pump	19.015	19.015
Fuel Pool Cooling Pump	Type 1B (1 x 1 x 2)	0.58	1.0	Diam of coupling 6" at 1,750 rpm spider coupling	Fuel Pool Cooling HX and Pump	19.015	19.015
Component Cooling Pump	Type 1B (1 x 1 x 2)	0.58	1.0	Diam of coupling 6" at 1,750 rpm spider coupling	Component Cooling HX and Pump	19.015	19.015
Quench Spray Pump	Type 1A (3/8" diam x 5" lg)	0.159	0.11	DBC is 6" at 3,600 rpm	Quench Spray Pump	22.05	200.54
Refueling Water Recirc. Pump	Type 1B (1 x 1 x 2)	0.58	1.0	Diam of coupling 6" at 1,750 rpm spider coupling	Quench Spray Pump	19.015	19.015
Chemical Addition Recirc. Pump	Type 1B (1 x 1 x 2)	0.58	1.0	Diam of coupling 6" at 1,750 rpm spider coupling	Refueling Water Tank	19.015	19.015
Electrical Aux. Feed Pump	Type 1A (3/8" diam x 5" lg)	0.159	0.11	DBC is 6" at 3,560 rpm	Aux. Feed Pumps	22.05	200.54
Turbine Aux. Feed Pump	Type 2 (1.5 x 1.5 x 1.5)	0.978	2.25	Diam of wheel 19" at 4,200 rpm	Aux. Feed Pumps	1852	823.1
Plant Bottle Storage	Type 3	2.0	0.5	Bottle pressure 2,600 psi	Refueling Water Tank	3828	7656

TABLE 5.2-15 (CONT'D)

INTERNAL MISSILE SUMMARY

Missile Source	Missile (See Notes)	Actual Weight (lb)	Actual Impact Area (in.^{2})	Speed Torque or Pressure	Targets	Type KE (ft-lb)	Type KE/A (ft-lb/in.^{2})
Control Room Air Bottles	Type 3	2.0	0.5	Bottle pressure 2,000 psi	Leak Detection Exhaust Fan	Less than 3828	Less than 7656
Propane Bottles	Type 3	2.0	0.5	Bottle pressure 264.7 psi	Refueling Water Tank	Less than 3828	Less than 7656
CO_2 Storage Bottle	Type 3	2.0	0.5	Bottle pressure 305 psi	Fuel Pool Cooling HX and Pump	Less than 3828	Less than 7656
Control Room Air Compressor	Type 4 (1" diam x 8 1/4" lg)	3.03	0.785	Compress pressure 2,500 psi Diam of diaphragm 9.095 in. 12 bolts 1"-12UNF-2A x 8 1/4" lg	Leak Detection Exhaust Fans	601	765.6
Aux. Bldg. Supply Fan	Type 5	87.0	15.0	Diam of fan 30" at 1,390 rpm	Leak Detection Exhaust Fans	54240	3616
Purge Exhaust Fan	Type 5	87.0	15.0	Diam of fan 40" at 1,220 rpm	Leak Detection Exhaust Fans	54240	3616

Notes:

Types of Possible Missiles

1. Pump motor coupling (A) bolt (B) gear tooth
2. Turbine blade less energy required to penetrate casing
3. Bottle blowout plug or valve regulator
4. Compressor head bolt and nut 100% stored strain energy transformed into K.E.
5. Fan blade less energy required to penetrate the fan housing. 40" diam fan at 1,220 rpm gives greatest K.E. generated by the fans. 40" diam fan at 1,390 rpm gives greatest penetration ability. Number indicates K.E. after penetration.

TABLE 5.3-1

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Reactor Coolant System Charging	15	A	3	Check	Auto-Trip	Open	Open	Closed	AS-IS	Liquid	SIS	55-(4)	Check	10	Check	MOV (Gate)	Check	MCC-E5	9.1-1
Component Cooling to Reactor Coolant Pumps (17)	58,17,18	A	6	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	20	20	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Component Cooling to Shroud Coolers (17)	16	A	6	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	20	20	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Seal Injection Water to Reactor Coolant Pump	35,36,37	A	2	Check	Rem-Man	Open	Open	Open	AS-IS	Liquid	None	FSAR 5.3.3.6	Check	10	Check (Spring Loaded)	MOV (Gate)	Check	MCC-E3	9.1-1
Primary Grade Water to Pressurizer Relief Tank	45	A	3	Check	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA	56-(4)	Check	8	Check (Spring Loaded)	TV (Diaphragm)	Check	CA	None
Nitrogen Supply to Pressurizer Relief Tank	49	A	3/4	Check	Auto-Trip	Closed	Closed	Closed	Closed	Gas	CIA	56-(4)	Check	5	Check (Spring Loaded)	TV (Globe)	Check	CA	None
Main Condenser Ejector Vent	89	D	6	Check	Auto-Trip	Closed	Closed	Closed	Closed	Gas	CIB	56-(4)	Check	20	Check (Weight Loaded)	TV (Globe)	Check	CA	None
Nitrogen Supply to Safety Injection Accumulators	53	A	1	Auto-Trip	Auto-Trip	Closed	Closed	Closed	Closed	Gas	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	6.3-1
Component Cooling from Reactor Coolant Pump B & C Thermal Barriers (17)	8	A	3	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	8	8	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Reactor Coolant Pump - Seal Water Return (17)	19	A	3	Auto-Trip Check Valve	Auto-Trip	Open	Open	Closed	AS-IS	Liquid	CIA	55-(4)	10	10	MOV (Gate) Check (Spring Loaded)	MOV (Gate)	MCC-E5	MCC-E6	9.1-1
Component Cooling from Reactor Coolant Pump B & C Motors (17)	25	A	6	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	8	8	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Reactor Coolant System Letdown (17)	28	A	2	3 Auto-Trip	Auto-Trip	Open	Sometimes Closed	Closed	Closed	Liquid	CIA	55-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	9.1-1
			2	Rem-Man		Closed	Sometimes Open	Closed	AS-IS	Liquid	None	FSAR 1A.55							
Primary Drain Transfer Pump No. 1 Discharge (17)	29	A	2	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Reactor Containment Sump Pump Discharge (17)	38	A	2	Auto-Trip	Auto-Trip	Sometimes Open	Sometimes Open	Closed	Closed	Liquid	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Component Cooling from Reactor Coolant Pump A Thermal Barrier (17)	26	A	2	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Component Cooling from Reactor Coolant Pump A Motor (17)	27	A	4	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	8	8	TV (Globe)	TV (Globe)	CA	CA	9.4-1

TABLE 5.3-1 (CONT'D)

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Air Activity Monitor Return to Containment	43	A	1	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Gas	CIA[9]	56-(4)	5	5	TV (Globe)	TV (Globe)	SOV	SOV	5.4-3
Primary Vent Header	48	A	1 1/2	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Gas	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Safety Injection Accumulators Sample (17)	55-1	A	3/8	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Pressurizer Relief Tank Gas Sample	55-4	A	3/8	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Gas	CIA	55-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Pressurizer Liquid Space Sample (17)	56-1	A	3/8	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIA	55-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Reactor Coolant Cold Leg Samples (17)	56-2	A	3/8	Auto-Trip	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA(9)	55-(4)	5	5	TV (Globe)	TV (Globe)	SOV	SOV	None
Reactor Coolant Hot Leg Samples (17)	56-3	A	3/8	Auto-Trip	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA(9)	55-(4)	5	5	TV (Globe)	TV (Globe)	SOV	SOV	None
Pressurizer Vapor Space Sample (17)	105-2	A	3/8	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Gas	CIA	55-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None
Component Cooling Water from Residual Heat Exchangers and Residual Heat Removal Pump Seal Coolers (17)	2,4	D	18	Rem-Man	Manual	Closed	Sometimes Open	Closed	AS-IS	Liquid	None	56-(1) FSAR 1A.56	60	Manual	MOV (Butterfly)	Manual (Butterfly)	A: MCC-E5 B: MCC-E6	Manual	9.4-1
Component Cooling Water to Residual Heat Exchangers and Residual Heat Removal Pump Seal Coolers (17)	1,5	D	18	Rem-Man	Manual	Closed	Sometimes Open	Closed	AS-IS	Liquid	None	56-(1) FSAR 1A.56	60	Manual	MOV (Butterfly)	Manual (Butterfly)	A: MCC-E5 B: MCC-E6	Manual	9.4-1
Air Recirculation Cooling Water - In (17)	14	A	8	Auto-Trip	Auto-Trip	Open	Open	Closed/ Open	Closed	Liquid	CIB	56-(4)	20	20	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Air Recirculation Cooling Water - out (17)	11	A	8	Auto-Trip	2 Auto-Trip	Open	Open	Closed/ Open	Closed	Liquid	CIB	56-(4)	20	20	TV (Globe)	TV (Globe)	CA	CA	9.4-1
Steam Generator Blowdown	39,40,41	B	3	Sealed System	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIA	57	Sealed System	8	Sealed System	TV (Globe)	Sealed System	CA	10.3-6
Steam Generator Blowdown Samples	56-4, 105-1, 97-4	B	3/8	Sealed System	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIA	57	Sealed System	5	Sealed System	TV (Globe)	Sealed System	CA	None
Feedwater	76,77,78	B	16	Sealed System	Nonreturn	Open	Open	Closed	Closed	Liquid	FWI	57	Sealed System	60	Sealed System	MOV (Nonreturn)	Sealed System	MCC-E5	10.3-5
			3	Sealed System	Check	Closed	Sometimes Open	Open	AS-IS	Liquid	None	FSAR 5.3.3.9	Sealed System	Check	Sealed System	Check	Sealed System	Check	10.3-5
Residual Heat Removal Inlet and Outlet Sample (17)	97-1, 97-2	A	3/8	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	97-1 Liquid 97-2 Liquid	CIA	56-(4)	5	5	TV (Globe)	TV (Globe)	CA	CA	None

TABLE 5.3-1 (CONT'D)

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Component Cooling Water from Shroud Coolers (17)	9	A	6	Auto-Trip	Auto-Trip	Open	Open	Closed	Closed	Liquid	CIB	56-(4)	20	20	TV (Globe)	TV (Globe)	CA	CA	9.4-1
River Water to Recirculation Spray Heat Exchangers	79,80,81, 82	C	14	Sealed System	Rem-Man	Open	Open	Open	AS-IS	Liquid	None	57	Sealed System	60	Sealed System	MOV (Butterfly)	Sealed System	A&C: MCC-E5 B&D: MCC-E6	9.9-1
River Water from Recirculation Spray Heat Exchangers (17)	83,84,85, 86	C	14	Sealed System	Rem-Man Manual	Open Open	Open Open	Open Open	AS-IS AS-IS	Liquid Liquid	None None	57 FSAR 5.3.3.10	Sealed System	60 Manual	Sealed System	MOV (Butterfly) Ball	Sealed System	A&C: MCC-E5 B&D: MCC-E6	9.9-1
High Head Safety Injection to Hot Legs	7,33	C	3	Check	Rem-Man	Closed	Closed	Closed/ Open	AS-IS	Liquid	None	FSAR 5.3.3.1	Check	10	Check	MOV (Gate)	Check	869A: MCC-E5 869B: MCC-E6	6.3-8
Low Head Safety Injection	60,61,62	C	6	Check	Rem-Man	Closed (60,62) Open (61)	Closed (60,62) Open (61)	Closed (60,62) Open (61)	AS-IS AS-IS	Liquid	None	FSAR 5.3.3.1	Check	10	Check	MOV (Venturi Gate)	Check	890A: MCC-E5 890 B&C: MCC-E6	6.3-8
Quench Spray Pump - Discharge	63,64	C	10	Check	Auto-Trip	Closed	Closed	Open	AS-IS	Liquid	CIB	FSAR 5.3.3.5	Check	62 (to open)	Check (Weight Loaded)	MOV (Gate)	Check	A: MCC-E5 B: MCC-E6	6.4-1A
Outside Recirculation Spray Pump - Discharge	70,71	C	10	Check	Auto-Trip	Open	Open	Open	AS-IS	Liquid	CIB	FSAR 5.3.3.5	Check	60 (to open)	Check (Weight Loaded)	MOV (Gate)	Check	A: MCC-E5 B: MCC-E6	6.4-1B
Boron Injection (High Head Safety Injection to Cold Legs)	113	C	3	Check	2 Auto-Trip	Closed	Closed	Open	AS-IS	Liquid	SIS	FSAR 5.3.3.1	Check	867C: 10 (to oper) 867D: 15 (to oper.)	Check	2 MOV (Gate)	Check	867C: MCC-E5 867D: MCC-E6	6.3-8
High Head Safety Injection to Cold Legs	96	C	3	Check	Rem-Man	Closed	Closed	Closed/ Open	AS-IS	Liquid	None	FSAR 5.3.3.1	Check	10	Check	MOV (Gate)	Check	MCC-E5	6.3-8
Outside Recirculation Spray Pump Suction from Containment Sump	66,67	C	12	None	Rem-Man	Open	Open	Open	AS-IS	Liquid	CIB	FSAR 5.3.3.2	None	60	None	MOV (Gate)	None	A: MCC-E5 B: MCC-E6	6.4-1B
Low Head Safety Injection Pump Suction from Containment Sump	68,69	C	12	None	Rem-Man	Closed	Closed	Open (6)	AS-IS	Liquid	None	FSAR 5.3.3.2	None	120	None	MOV (Gate)	None	860A: MCC-E5 860B: MCC-E6	6.3-8
Containment to Air Activity Monitor	44	A	1	None	2 Auto-Trip in Series	Open	Open	Closed	Closed	Gas	CIA	56-(4) FSAR 1.3.3.11	None	5	None	TV (Globe)	None	CA	5.4-3

TABLE 5.3-1 (CONT'D)

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Containment Vacuum Pump/Hydrogen Recombiner Suction	92,93	A	2	None	2 Auto-Trip in Series; 2 Manual	One Open/ One Closed	One Open/ One Closed	Closed/ Open	Closed	Gas	CIA(9)	FSAR 5.3.3.8	None	5	None	2-TV (Globe)	None	CA,SOV	5.4-3
						Closed	Closed	Closed	AS-IS	Gas	None	FSAR 5.3.3.8	None	Manual	None	2 Manual (Ball)	None	Manual	6.5-1
Reactor Coolant System Fill	46	D	2	Check	Rem-Man	Closed	Sometimes Open	Closed	Closed	Liquid	None	56-(2) FSAR 1A.56	Check	5	Check (Spring Loaded)	TV (Globe)	Check	CA	9.1-1
Safety Injection Accumulator Make-up	20	A	1	Check	Manual	Closed	Sometimes Open	Closed	AS-IS	Liquid	None	56-(2)	Check	Manual	Check (Spring Loaded)	Manual (Globe)	Check	Manual	6.3-1
Residual Heat Removal to Refueling Water Storage Tank	24	D	6	2 Manual	Manual	Closed	Closed	Closed	AS-IS	Air	None	56-(1)	Manual	Manual	Manual (Gate) (Ball)	Manual (Gate)	Manual	Manual	9.3-1
Fuel Transfer Tube	65	D	20	Blind Flange	None					Liquid	None	FSAR 5.3.3.3 9.12.2.2	Blind Flange	None	Blind Flange	None	Blind Flange	None	5.3-1
Safety Injection Accumulator Test Line	106	D	3/4	Auto-Trip	Auto-Trip	Closed	Closed	Closed	Inside: AS-IS Outside: Closed	Air	CIA	56-(4)	10	5	MOV (Globe)	TV (Globe)	MCC-E6	CA	6.3-1
Containment Purge Exhaust	90	D	42	Auto-Trip (7)	Auto-Trip (7)	Closed	Closed	Closed	AS-IS	Gas	Valves trip shut on containment high-high radiation during normal operation or refuel-ing (7)	56-(1)	8	8	MOV (Butter-fly)	MOV (Butter-fly)	MCC-E12	MCC-E11	5.4-1
Containment Purge Supply	91	D	42	Auto-Trip (7)	Auto-Trip (7)	Closed	Closed	Closed	AS-IS	Gas	Valves trip shut on containment high-high radiation during normal operation or refuel-ing (7)	56-(1)	11	8	MOV (Butter-fly)	MOV (Butter-fly)	MCC-E12	MCC-E11	5.4-1
Containment Vacuum Ejector Suction	94	D	8	Manual	Manual	Closed	Closed	Closed	AS-IS	Gas	None	56-(1)	Manual	Manual	Manual (Butter-fly)	Manual (Butter-fly)	Manual	Manual	5.4-3

TABLE 5.3-1 (CONT'D)

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Refueling Cavity to Purification Pump Suction	104	D	6	Manual	Manual	Closed	Closed	Closed	AS-IS	Air	None	56-(1)	Manual	Manual	Manual (Ball)	Manual (Ball)	Manual	Manual	9.5-1
Purification Pump Discharge to Refueling Cavity	103	D	6	Manual	Manual	Closed	Closed	Closed	AS-IS	Air	None	56-(1)	Manual	Manual	Manual (Ball)	Manual (Ball)	Manual	Manual	9.5-1
Compressed Air to Containment	42	D	2	Check	Manual	Closed	Open/ Closed	Closed	AS-IS	Gas	None	56-(2)	Check	Manual	Check (Spring Loaded)	Manual (Gate)	Check	Manual	9.8-1
Instrument Air	47	D	2	Check	Manual	Closed	Closed/ Open	Closed/ Open	AS-IS	Gas	None	56-(2)	Check	Manual	Check (Spring Loaded)	Manual (Gate)	Check	Manual	9.8-1
Pressurizer Dead Weight Calibrator	110	D	1/8	None	2 Manual in series	Closed	Closed/ Open	Closed	AS-IS	Gas	None	FSAR 5.3.3.4	None	Manual	None	Manual (Globe)	None	Manual	None
Containment Leakage Monitoring - Open Taps and Containment Wide Range Pressure Monitoring	55-2, 57-1, 97-3, 57-2	A	3/8(8)	None	Manual Valve (11) and capped pipe	Closed	Closed	Closed	AS-IS	Gas	None	FSAR 5.3.3.4	None	Manual	None	Manual (Globe)	None	Manual	5.4-3
Post DBA Hydrogen Control Discharge to Containment	87,88	A	2	None	2 Manual in series	Closed	Closed	Closed/ Open	AS-IS	Gas	None	FSAR 5.3.3.8	None	Manual	None	Manual (Ball)	None	Manual	6.5-1
Main Steam (17)	73,74,75	B	32	Sealed system	Auto-Trip	Open	Closed/ Open	Closed	Closed[12]	Steam	SLI	57	Sealed System	5	Sealed System	TV (Nonreturn)	Sealed System	CA	10.3-1
Main Steam to Turbine Drive for Steam Generator Auxiliary Feed Pump (17)	73,74,75	B	3	Sealed System	Rem-Man	Open	Open/ Closed	Open	AS-IS	Steam	None	57	Sealed System	30	Sealed System	MOV (Gate)	Sealed System	MCC-E6	10.3-1
Main Steam Safety Valves (17)	73,74,75	B	6	Sealed System	Safety Valves	Closed	Closed	Closed	Closed	Steam	None	57	Sealed System	--	Sealed System	Safety Valves	Sealed System	--	10.3-1
Main Steam Atmospheric Dump Valves (17)	73,74,75	B	6	Sealed System	Pressure Control Valves	Closed	Open/ Closed	Closed/ Open	Closed	Steam	None	57	Sealed System	--	Sealed System	Control Valve (Globe)	Sealed System	CA	10.3-1
Main Steam Line Drains (17)	73,74,75	B	1 1/2	Sealed System	Auto-Trip	Open	Open	Closed	Closed	Liquid	SLI	57	Sealed System	5	Sealed System	TV (Globe)	Sealed System	CA	10.3-1
Main Steam Residual Heat Release Valve (17)	73,74,75	B	4	Sealed System	Residual Heat Release Valve	Closed	Closed/ Open	Closed/ Open	Closed	Steam	None	57	Sealed System	--	Sealed System	Control Valve (Globe)	Sealed System	CA	10.3-1
Main Steam Isolation Bypass (17)	73,74,75	B	2	Sealed System	Rem-Man	Closed	Closed	Closed	AS-IS	Steam	SLI	57	Sealed System	--	Sealed System	MOV	Sealed System	MCC E06	10.3-1
Containment Hydrogen Monitoring System	95,109	C	3/8	SOV	SOV	Closed	Closed	Open	Closed	Gas	None	56-(4)	--	--	SOV (Globe)	SOV (Globe)	PNL-DC2 Train B PNL-DC3 Train A	PNL-DC2 Train B PNL-DC3 Train A	6.5-4

TABLE 5.3-1 (CONT'D)

CONTAINMENT ISOLATION ARRANGEMENTS

Service	Penet. No.	Penet. Class	Nominal Line Size	Isolation Valves Provided (16) Inside	Isolation Valves Provided (16) Outside	Isolation Valve Position Normal	Isolation Valve Position Shutdown (13)	Isolation Valve Position DBA (14)	Isolation Valve Position Failure (15)	Fluid Contained	Auto Actuation Signal (1)	1971 GDC Or Exception Met (2)	Valve Closure Time (Sec) (5) Inside	Valve Closure Time (Sec) (5) Outside	Valve Type (3) Inside	Valve Type (3) Outside	Power Source (4) Inside	Power Source (4) Outside	FSAR Fig. No.
Personnel Air Lock (PH-P-1)	None	D	1 1/2	2 Manual in Series	2 Manual in Series	Admin. Closed	Closed	Closed	AS-IS	Air	None	56	Manual	Manual	Ball	Ball	Manual	Manual	5.2-23
Emergency Air Lock (PH-P-2)	None	D	2	Manual	Manual	Admin. Closed	Closed	Closed	AS-IS	Air	None	56	Manual	Manual	Ball	Ball	Manual	Manual	5.2-23
Reactor Vessel Level Instrumentation System (RVLIS)	95,109	D	1/4	None	(10)	--	--	--	--	Liquid	None	FSAR 5.3.3.7	--	--	None	--	--	--	None
Fire Protection - Containment Hose Reel Stations	13	D	4	Check	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA	56	Check	15	Check (Weight Loaded)	TV (Globe)	Check	CA	None
Fire Protection - Containment Cable Penetrations	31	D	4	Check	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA	56	Check	15	Check (Weight Loaded)	TV (Globe)	Check	CA	None
Fire Protection - Containment RHR Platform	32	D	3	Check	Auto-Trip	Closed	Closed	Closed	Closed	Liquid	CIA	56	Check	15	Check (Weight Loaded)	TV (Globe)	Check	CA	None

Notes:

(1) Sections 7.3 and Tables 7.3-1 and 7.3-2 describe actuation signals.

(2) 1971 General Design Criterion met is listed with appropriate subparagraph in parentheses. Exceptions to General Design Criterion arrangements are noted by explanatory Updated FSAR section numbers.

(3) MOV = Electric Motor Operated Valve
TV = Trip Valve

(4) For electric motor-operated valves (MOVs) the appropriate motor control center is listed. Those which have an even number receive power from Emergency Generator 2. Those which have an odd number receive power from Emergency Generator 1 (Section 8.5). For air-operated trip valves (TVs), the power supply is designated CA for compressed air (Section 9.8). For solenoid operated trip valves (TVs), the power supply is designated SOV for solenoid operator. Secondary modes of operation are provided for MOVs in the form of manually operated (handwheels) overrides; for TVs, CA pressure can be bled off or solenoid operator can be de-energized to trip valves to fail-safe positions. Manual and check valves have no specific secondary modes of operation.

(5) Closure times listed for air-operated trip valves are calculated assuming no plug weight or stem friction. All times listed are design values.

(6) Opened to shift low head safety injection from refueling water storage tank to containment sump (Section 6.3).

(7) Containment purge isolation valves are normally shut, remote manually operated, administratively controlled valves, meeting General Design Criterion 56-(1). During refueling operations, these valves are opened and will trip shut automatically on receipt of a containment high-high radiation signal (Section 11.3).

(8) Each of the containment leakage monitoring and containment wide range pressure monitoring lines have a one-eighth inch orifice on the inside of containment located adjacent to the three-eighth inch penetration, consistent with the requirement of Safety Guide 11 (Section 1.3). Penetrations 57-3 and 57-4 have been capped inside and outside of containment.

(9) CIA can be overridden for sample inlet valves (Section 9.6.1.1).

(10) Hydraulic isolation device.

(11) Penetrations 55-2, 57-1, 57-2, and 97-3 are isolated outside of containment downstream of the containment pressure instrumentation by a sealed manual valve and pipe cap.

(12) Main Steam Isolation Valve fails closed on loss of air and fails AS-IS on loss of 125 VDC.

(13) Shutdown position in Modes 3 and 4.

(14) DBA position is for LBLOCA.

(15) Failure position is for power failure.

(16) Relief valves listed in Licensing Requirements Manual Table 5.1-1.

(17) Relief valve between isolation valves.

SECTION 6

ENGINEERED SAFETY FEATURES

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Figure 6.4-9	Revision 0	January, 1982
Figure 6.4-10	Revision 8	January, 1990

LIST OF EFFECTIVE PAGES (CONT'D)

Page Numbers	Revision in Effect	Date
Figure 6.5-1 (Deleted)	Revision 18	January, 2000
Figure 6.5-2 (Deleted)	Revision 16	January, 1998
Figure 6.5-3 (Deleted)	Revision 16	January, 1998
Figure 6.5-4 (Deleted)	Revision 18	January, 2000
Notes for Figures 6.5-1 & -4 (Deleted)	Revision 18	January, 2000
Figure 6.6-1	Revision 18	January, 2000
Figure 6.6-1B (Deleted)	Revision 18	January, 2000
Figure 6.6-2 (Deleted)	Revision 18	January, 2000

LIST OF FIGURES

LIST OF FIGURES (CONT'D)

Piping Class II (Q2)

This classification encompasses the following:

1. Residual heat removal system
2. Reactor coolant letdown and charging portions of chemical and volume control system
3. Portions of the emergency core cooling and containment depressurization systems that may recirculate reactor coolant
4. Portions of the main steam and feedwater systems extending from and including the secondary side of the steam generator up to and including the outermost containment isolation valves and connected piping up to and including the first isolation valve
5. Those portions of any other system used to effect isolation of containment
6. High pressure portion of gaseous waste disposal system.

Piping Class III (Q3)

This classification encompasses the following:

1. Chemical and volume control system including piping from boric acid tanks to charging pumps but excluding portions defined above as Class II and portions defined as QA Category II in accordance with Appendix A, "Quality Assurance."
2. Containment depressurization system excluding those portions covered in Class II
3. Accumulator and refueling water supply subsystems of the emergency core cooling system
4. Auxiliary feedwater system
5. Portions of the component cooling and river water systems that transfer heat from systems for emergency core cooling, containment depressurization, residual heat removal and reactor coolant letdown
6. Vents and drains from Class I and Class II systems (except portions defined as QA Category II in accordance with UFSAR Appendix A, Quality Assurance)
7. Any portion of primary plant not classified as Class I or II
8. The reactor vessel flange leak detection lines up to and including valve SOV-RC-544.

6.2.2.2 Protection of Class I Piping

Class I piping systems are protected from damage due to whipping pipe from other systems by one of the following methods:

1. Class I pipe and equipment are shielded by a protective wall or enclosure

2. Class I pipe and equipment are separated from non-Class I systems that could cause damage by a distance that is sufficient to prevent damage.

Where a Class I system cannot be protected as in 1 or 2 above from a non-Class I system, the portion of the non-Class I system that threatens the Class I system is reclassified to Class I and is designed to the following criteria:

1. Failure of the piping is precluded due to conservative piping, hanger and support design

2. In the unlikely events of severance of a pipe, the pipe restraints are so placed that whipping is impossible, or, if that is impractical, so that the maximum length of whipping pipe is of a length that is insufficient to reach the systems being protected.

6.2.3 Motors

6.2.3.1 Motors Located Outside the Containment

Motor electrical insulation systems are in accordance with ANSI, Internal Electronic and Electrical Engineers (IEEE) and National Electrical Manufacturers Association (NEMA) standards and are tested as required by these standards. Temperature rise design is selected such that normal long life is achieved even under accident loading conditions. Periodic electrical insulation tests will be made during the lifetime of the equipment to detect deterioration, if any, of the insulation system.

6.2.3.2 Motors Located Inside the Containment

The motors are selected to ensure operation during DBA conditions. Motor electrical insulation systems are in accordance with ANSI, IEEE and NEMA standards. The motors are tested as required by these standards. Winding insulation systems are provided which can operate at temperatures in excess of those calculated to occur under DBA conditions. Prototype tests are performed on each motor type required for operation after a DBA. Periodic electrical insulation tests will be made during the life of the equipment to detect any deterioration of the insulation to ensure that motors remain in a reliable operating condition.

6.3.1.2 ECCS Single Failure Criterion Compliance

Active Failure Criteria

The ECCS is designed to accept a single active failure following the incident without loss of its protective function. The system design will tolerate the failure of any single active component in the ECCS itself or in the necessary associated service systems at any time during the period of required system operations following the incident.

A single active failure analysis is presented in Table 6.3-1 and demonstrates that the ECCS can sustain the failure of any single active component in either the short or long term and still meet the level of performance for core cooling.

Since the operation of the active components of the ECCS following a steam line rupture is identical to that following a LOCA, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

Passive Failure Criteria

The following philosophy provides for necessary redundancy in component and system arrangement to meet the intent of the AEC General Design Criteria on single failure as it specifically applies to failure of passive components in the ECCS. Thus, for the long term, the system design is based on accepting either a passive or an active failure.

Redundancy of Flow Paths and Components for Long Term Emergency Core Cooling

In the design of the ECCS, the following criteria are utilized:

1. During the long term cooling period following a LOCA, the emergency core cooling flow paths shall be separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the RCS.

2. Either of the two subsystems can be isolated and removed from service in the event of a leak outside the containment.

3. Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long term as a passive component.

4. Should one of these two subsystems be isolated in this long term period, the other subsystem remains operable.

5. Provisions are also made in the design to detect leakage from components outside the containment, collect this leakage and to provide for maintenance of the affected equipment.

Thus, for the long term emergency core cooling function, adequate core cooling capacity exists with an open flow path removed from service whether isolated due to a leak, because of blocking of one flow path, or because failure in the containment results in a spill of the delivery of one subsystem.

Subsequent Leakage from Components in Engineered Safety Features Subsystems

With respect to piping and mechanical equipment outside the containment, considering the provisions for visual inspection and leak detection, leaks will be detected before they propagate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of leak rate assuming only the presence of a seal retention ring around the pump shaft showed flow less than 50 gpm would result. Piping leaks, valve packing leaks or flange gasket leaks have been of a nature to build up slowly with time and are considered less severe than the pump seal failure.

Larger leaks in the ECCS are prevented by the following:

1. The piping is designed in accordance with ANSI B31.1-1967[6]

2. The seismic design for piping, equipment and supports ensures no loss of function for the Design Basis Earthquake

3. The system piping is located within a controlled area on the site

4. The piping system receives pressure tests and is accessible for periodic visual inspection

5. The piping is austenitic stainless steel which, due to its ductility, can withstand severe distortion without failure.

6.3.1.3 Codes and Classifications

Table 6.3-2 tabulates the codes and standards to which the ECCS components are designed.

6.3.2 System Design and Operation

6.3.2.1 System Description

Adequate emergency core cooling following a LOCA is provided by the ECCS shown in Figures 6.3-1, and 6.3-8 or 6.3-9. A simplified composite flow diagram of the entire ECCS is given as part of Figure 6.1-1, which is a composite flow diagram of the ESF. The system components operate in the following possible modes:

1. The injection mode in which any reactivity increase following the postulated accidents is terminated, initial cooling of the core is accomplished and coolant lost from the primary system in the case of a LOCA is replenished.

2. The recirculation mode in which long term core cooling is provided during the accident recovery period.

The initiation signal for core cooling by the safety injection charging pumps and the low head safety injection pumps is the safety injection signal (SIS) which is to be actuated by any of the following:

1. Low pressurizer pressure (two-out-of-three)

2. High containment pressure (two-out-of-three)

3. Low steam line pressure (two-out-of-three detectors in any one main steam line)

4. Manual actuation (1/2).

Injection Phase

The principle components of the ECCS which provide emergency core cooling immediately following a loss of coolant are the three accumulators (one for each loop), two of the three safety injection charging pumps (which perform the charging functions during normal operations) and the two low head safety injection pumps. The safety injection charging pumps are located in the auxiliary building. The two low head safety injection pumps are located in the safeguards area alongside the containment structure.

The accumulators, which are passive components, discharge into the cold legs of the reactor coolant piping when RCS pressure decreases below accumulator pressure thus ensuring rapid core cooling for large breaks. They are located inside the containment and are protected against possible missiles.

The SIS opens the boron injection header isolation valves and starts the safety injection charging pumps. The accumulator isolation valves also receive the SIS, even though these valves are normally open.

The safety injection charging pumps deliver borated water to the three cold legs of the reactor coolant loops during the injection phase. These pumps provide for the makeup of coolant and add negative reactivity following a small break which does not immediately depressurize the RCS to the accumulator discharge pressure. For large breaks, they start delivery through separate lines after the accumulators start their discharge.

The suction of the safety injection charging pumps is diverted from their normal suction at the volume control tank to the refueling water storage tank by the SIS. The pumps feed a common injection header. The injection header contains a boron injection tank on the discharge side of the safety injection charging pumps for addition of negative reactivity to the reactor cold legs with a minimum time delay. The tank contains boric acid solution and is isolated from the safety injection charging pumps discharge line by redundant, normally closed, parallel valves. The valves open upon receipt of a SIS. The refueling water flowing into the tank from the discharge of the safety injection charging pumps forces the boric acid solution out of the tank and into the RCS. Under normal operation there is continuous recirculation of the boric acid solution from the boron injection tank to the boron injection surge tank via a boron injection tank recirculation pump. The recirculation lines contain redundant isolation valves which close on a SIS.

For large pipe ruptures, the RCS is depressurized and voided of coolant rapidly and a high flow rate of emergency coolant is required to quickly cover the exposed fuel rods and limit possible core damage. This high flow is provided by the passive accumulators, followed by the charging pumps and the low head safety injection pumps which discharge into the cold legs of the RCS.

Manual valves in the ECCS are mainly those required for maintenance, refueling or test operations. Those manual valves that, if improperly positioned, would have an adverse effect on the performance of the ECCS, are administratively controlled in the correct position. The high head safety injection/charging pump recirculation line combined isolation valve (MOV-CH373) is administratively controlled in the deenergized and locked open position to prevent spurious closure. Manual throttle valves in the injection branch lines are properly adjusted by flow tests during system start-up testing.

A detailed listing of the instrumentation readouts of the main control board which the operator can monitor during the initial injection is given in Table 6.3-3.

Valves of the safety injection systems which are remotely operated and are normally in their ready position but do not receive a SIS have their positions indicated on a common portion of the control board. At any time during operation when one of these valves is not in the ready position for injection, it is shown visually on the board. In addition, an audible alarm alerts the operator to the condition.

Safety Injection Recirculation Phase

After the injection operation and when low level is reached in the refueling water storage tank, the reactor coolant and the injected refueling water spilled from the break and the water from the containment depressurization system (Section 6.4) collect in the containment sump and part is returned to the RCS by the low head safety injection pump(s). The balance flows to the recirculation spray subsystems.

Because the injection phase of the accident is terminated before the refueling water storage tank is completely emptied, all pipes are kept filled with water before recirculation is initiated. The low level setpoint on the RWST is set such that the containment sump level will be sufficient to provide adequate NPSH for the LHSI pumps when utilizing the sump suction path. Adequate NPSH for the LHSI pumps when utilizing the RWST suction path is available at the low level setpoint. Two out of the four RWST level indicators coincident with a safety injection signal will automatically initiate the transfer from injection to recirculation. The transfer occurs as described in Section 6.3.3.9.

If the break is large, depressurization of the RCS occurs rapidly due to the large rate of mass and energy loss through the break to the containment. For small breaks, the depressurization of the RCS by the ECCS and by the rupture during the injection phase can be augmented by secondary steam dump and auxiliary feedwater addition. Operator action to dump steam augments RCS depressurization but credit is not taken for this in the safety analysis in Section 14.

For the expected accident progression, no manual operator actions are required until after the symptoms have been diagnosed and the specific type of accident is identified. If abnormal conditions are present, the operating procedures will permit actions for feedwater and RCS temperature control prior to identification of the type of accident. The procedures also provide guidance in differentiating between the various types of accidents.

When the necessary depressurization has been accomplished, the low head safety injection pumps take suction from the containment sump and return the coolant to the reactor. If depressurization of the RCS proceeds slowly, recirculation of spilled coolant can be accomplished by aligning the discharge of the low head safety injection pumps with the suction of the safety injection charging pumps.

The redundant features of the ECCS recirculation loop include one pump in each of two separable and redundant trains with crossover capability at the discharge of each pump. Each pump takes suction through separate cross-connected lines from the containment sump.

The design of the containment sump and piping configuration from the containment sump to the low head safety injection pumps is illustrated in Figure 6.1-1.

After one day, the spray water collected is cold enough to reduce the temperature of the combined mass sufficiently for recirculation without flashing. The basis for this determination is from the plot of sump temperature versus time after the accident which is shown in Figure 14.3-58. All heat removal is through the recirculation spray subsystem. There are no heat exchangers in the ECCS.

Those portions of the ECCS 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. Shielding to maintain radiation levels within the guidelines set forth in 10 CFR 100.

2. Collection of discharges from pressure relieving devices into closed systems.

3. Means to detect and control radioactivity leakage into the environs, to the limits consistent with guidelines set forth in 10 CFR 100.

This criterion is met by minimizing leakage from the system. Recirculation loop leakage is discussed in Section 6.3.3.

Changeover from Injection Phase to Recirculation Phase

During the injection phase, the RWST level decreases to the low level set point at which time sufficient water is delivered to the containment sump via the containment depressurization system, the ECCS and from the RCS through the break to provide the required NPSH of the low head safety injection pumps to change to recirculation. The automatic transfer sequence is provided in Section 6.3.3.9.

Steam Break Protection

A large break of a main steam system pipe causes an uncontrolled removal of heat which rapidly cools the reactor coolant causing insertion of reactivity into the core. Compensation is provided by injection of boric acid solution from the boron injection tank into the cold legs. This system was originally designed and installed to maintain a nominal 12 weight percent concentration of the boric acid solution in the boron injection tank. Through a reanalysis of the large steam line break accident (Section 14.2.5) it was determined that a highly concentrated boric acid solution is not required. Therefore, to decrease the likelihood of boron solidification and thereby increase the reliability of the boron injection tank the boron concentration is maintained at a reduced level as specified in the Technical Specifications. All high head safety injection isolation valves, except the boron injection tank isolation valves, remain closed, thereby ensuring that the contents of the boron injection tank are emptied into the cold legs of the RCS with a minimum delay.

6.3.2.2 Components

All associated components, piping, structures and power supplies of the ECCS are designed to conform with Seismic Category I criteria (Appendix B). All components inside the containment are capable of withstanding or are protected from differential pressure which may occur during the rapid pressure rise to containment design pressure.

Accumulators

The accumulators are pressure vessels filled with borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the RCS by two check valves in series. If the RCS pressure falls below the accumulator pressure, the check valves open and borated water is forced into the RCS. Mechanical operation of the swing-disk check valves by means of differential pressure is the only action required to open the injection path from the accumulators to the core via the cold leg.

The level of borated water in each accumulator tank is adjusted remotely as required during normal station operation. Makeup water from the refueling water storage tank is added using the positive displacement hydrotest pump.

Water level is reduced by draining to the primary drain transfer tank. Samples of the solution in the accumulators are taken at the sampling station for periodic checks of boron concentration.

The accumulators are passive engineered safety features because the nitrogen gas pressure forces injection; no external source of power or signal transmission is needed to obtain fast acting, high flow capability when the need arises. One accumulator is connected to each of the cold legs of the RCS.

The accumulators are carbon steel, clad with stainless steel and designed to ASME Boiler and Pressure Vessel Code, Section III, Class C requirements. Redundant level and pressure indicators are provided with readouts on the control board. Each channel is equipped with high and low level alarms. The margin between the minimum operating pressure and design pressure provides a range of acceptable operating conditions within which the accumulator system meets its design core cooling objectives. The band is sufficiently wide to permit the operator to minimize the frequency of adjustments in the amount of contained gas or liquid to compensate for leakage. Limiting conditions for operation and surveillance are set forth in the Technical Specifications.

The accumulator design/operation parameters are listed in Table 6.3-5.

During outages, the accumulators may be used for pressurizing the discs of the reactor coolant system main loop stop valves to minimize seat leakage. This is accomplished by permanently installed tubing from the accumulators to the loop stop valves. The tubing is not permanently connected to either the loop stop valves or the accumulators during plant operation. Connection to the valves and accumulators is accomplished utilizing temporary hoses and quick disconnect couplings when needed.

Environmental qualification of ECCS equipment, inside the containment, which is required to operate following a LOCA is discussed in Section 7.3.2.1.2.

The quality standards of all ECCS components are tabulated in summary form in Table 6.3-4.

Boron Injection Tank

The boron injection tank is constructed of carbon steel and clad with stainless steel for corrosion resistance. The discharge from the safety injection charging pumps provides the motive force to inject the boric acid solution into the RCS.

Redundant tank strip heaters and line heat tracing are provided to ensure that the boric acid solution is stored at a temperature in excess of the solubility limit as specified in the Technical Specifications.

The boron injection tank has two temperature detectors; both provide heater control, control room alarm and local indication.

Continuous recirculation between the boron injection tank (BIT) and the boron injection surge tank ensures that the BIT contains boric acid solution at all times.

Table A.1-1 identifies the portions of the equipment employed with the BIT which are designed as Category I.

The design parameters are presented in Table 6.3-6.

Boron Injection Surge Tank

The boron injection surge tank provides surge capacity for the BIT recirculation loop. The boron injection surge tank contains the same concentration of boric acid as the BIT during normal plant operation. The recirculation lines to and from the surge tank are automatically isolated by valves which receive the SIS.

Pumps

Charging pumps, which are also used as high head safety injection pumps, supply borated water to the RCS. The pumps are of the horizontal centrifugal type, driven by electric motors. Minimum operating requirements are provided in the periodic operating surveillance tests for these pumps. Procedure references are provided to ensure a safety evaluation is performed when pump performance requirement changes could affect accident analysis assumptions.

The low head safety injection pumps are a vertical centrifugal pump equipped with a turbulence limiter and anti-vortexing devices (cruciforms and grating) to reduce vortexing and a false bottom pump-can to lower pump vibrations. These pumps supply borated water to the RCS during the safety injection and recirculation mode. The head-flow curve for the low head pumps is given in Figure 6.3-5.

All pressure containing parts of the pumps were chemically and physically analyzed and the results were checked to ensure conformance with the applicable ASTM specification. In addition, all pressure containing parts of the pump were liquid penetrant inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Appendix VIII. The acceptance standard for the liquid penetrant test is ANSI B31.1, Case N-10. Parts of the pump in contact with borated water are stainless steel or equivalent corrosion resistant material.

The pressure containing parts of the pumps are castings conforming to ASTM A-351[7] Grade CF8 or CF8M, or equivalent.[32] Stainless steel forgings were procured per ASTM A-182[8] Grade F 304 or F 316 or ASTM A-336,[9] Class F8 or F8M, or equivalent.[32] Stainless steel plate was constructed to ASTM A-240[10] Type 304 or 316, or equivalent.[32] All bolting material conforms to ASTM A-193[11] or equivalent.[32]

Materials such as weld-deposited Stellite, Chromaloy or equivalent[32] are used at points of close running clearances in the pumps to prevent galling and to ensure continued performance capability in high velocity areas subject to erosion.

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 adequate allowances have been made for shaft deflection and clearances between stationary parts. Table 6.3-7 lists the design parameters for the safety injection charging and low head safety injection pumps.

Where welding of pressure containing parts was necessary, a welding procedure including joint detail was submitted for review and approval. The procedure includes evidence of qualification necessary for compliance with the ASME Boiler and Pressure Vessel Code, Section IX. This requirement also applies to any repair welding performed on pressure containing parts.

The pressure containing parts of the pump were assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump is given a complete shop performance test in accordance with Hydraulic Institute Standards. The pumps were run at design flow and head, shutoff head and three additional points to verify performance characteristics. Where NPSH was critical, this value was established at design flow by means of adjusting suction pressure.

Boron Injection Recirculation Pumps

Two boron injection recirculation pumps are provided to recirculate the boric acid solution continuously around a closed loop consisting of the BIT, the boron injection surge tank and associated valves and piping. One pump is in continuous operation while the other pump provides a maintenance spare.

Valves

All parts of valves used in the ECCS 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 position indication in the main control room.

Exceptional tightness is specified for all valves and, where possible, such as instrument valves, packless diaphragm valves are used. All valves, except those which perform a control function, are provided with backseats which are capable of limiting leakage

2. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conform to ASTM A-376[27] or its equivalent[32] and meet the supplementary requirement S6 for ultrasonic testing.

3. Fittings conform to the requirements of ASTM A-403[28] or its equivalent.[32]

Shop fabrication of piping subassemblies was performed in accordance with specifications which define and govern material procurement, detailed design, shop fabrication, cleaning, inspection, packaging and shipment.

Welds for pipes sized 2.5 inches and larger were butt welded except for those welds in the LHSI pump suction piping within the valve pit, which were made when removing the two 12 inch manually operated maintenance valves at the suction of each of the LHSI pumps and reinstalling them as MOV-SI862A and B (see Figure 6.3-8 or 9). These piping welds were made using slip on couplings, fillet welded to the joined components. A piping flexibility analysis has confirmed the acceptability of these welds in lieu of butt welds. Reducing tees were used where the branch size exceeds one-half of the header size. Branch connections of sizes that were equal to or less than one-half of the header size were of a design that conforms to the ANSI rules for reinforcement set forth in the ANSI B31.1. Bosses for branch connections were attached to the header by means of full penetration welds.

All welding was performed by welders and welding procedures qualified in accordance with the ASME Boiler and Pressure Vessel Code, Section IX. The shop fabricator was required to submit all welding procedures and evidence of qualifications for review and approval prior to release for fabrication. All welding materials used by the shop fabricator must have prior approval.

All high pressure piping butt welds containing radioactive fluid, at greater than 600°F temperature and 600 psig pressure, were radiographed. The remaining piping butt welds were randomly radiographed. The technique and acceptance standards were those outlined in N-624.2 and N-625.3 of the ASME Boiler and Pressure Vessel Code, Section III. In addition, butt welds were liquid penetrant examined in accordance with the procedure of ASME Boiler and Pressure Vessel Code, Section III, Paragraph N-627.2 and the acceptance standard as defined in Paragraph N-627.3. Finished branch welds were liquid penetrant examined on the outside and the root passes were examined for sizes 6 inches and larger and for schedule 80S and heavier for all sizes.

A post bending solution anneal heat treatment was performed on hot formed stainless steel pipe bends. Completed bends were then completely cleaned of oxidation from all affected surfaces. The shop fabricator was required to submit the bending, heat treatment and cleanup procedures for review and approval prior to release for fabrication.

General cleaning of completed piping subassemblies (inside and outside surfaces) was governed by basic ground rules set forth in the specifications. For example, these specifications prohibited the use of hydrochloric acid and limit the chloride content of service water and demineralized water.

Packaging of the piping subassemblies for shipment was done so as to preclude damage during transit and storage. Openings were closed and sealed with tight fitting covers to prevent entry of moisture and foreign material. Flange facings and weld end preparations were protected from damage by means of wooden cover plates and securely fastened in position. The packing arrangement proposed by the shop fabricator was subject to approval.

Pump and Valve Motors

Motors Outside the Containment

Motor electrical insulation systems were supplied and tested in accordance with ANSI, IEEE and NEMA standards.

Temperature rise design selection was such that normal long life is achieved even under accident loading conditions.

Motors Inside the Containment

Motors for those valves inside containment which must operate during and/or following the LOCA were designed for continuous service in the environmental conditions following the accident. This assures that the valves can perform their required safety function during the recovery period. Periodic operations of the motors and tests of the insulation ensure that the motors remain in a reliable operating condition. The only motors of the ECCS which must operate inside the containment are valve motors.

Although these motors, which are provided only to drive ESF equipment, are normally run only for test, the design loading and temperature rise limits are based on the accident conditions.

Normal design margins are specified for these motors to make sure the expected lifetime includes allowance for the occurrence of accident conditions.

components can be accomplished from the control room. In analysis of system performance, delays in reaching the programmed trip points and in actuation of components were conservatively established on the basis that only emergency onsite power is available.

The starting sequence of the safety injection charging pumps, the low head safety injection pumps and the related emergency power equipment is designed so that delivery of the full rated flow is reached within 25 seconds after the process parameters reach the setpoints for the injection signal. Reference is made to Section 8.5.

For the small break analysis, an additional delay time is allowed for the SIS to activate when the appropriate setpoint is reached.

Piping Restraints

Following a SIS, the maximum velocity of water is approximately 110 fps in the accumulator discharge lines and 40 fps in the high head safety injection system lines (assuming two pumps deliver through 3 inch common cold injection lines). When the RCS pressure falls below the accumulator pressure, the check valve opens and borated water is forced into the coolant system. The resultant hydraulic forces are controlled by supports, including snubbers and limit stops located at various points in the piping system. Supports in the accumulator discharge lines do not eliminate the potential for water hammer, however, water hammer is not expected, since the relative low pressure of the low-head safety injection pumps would not rapidly close the check valves.

The snubbers are of the hydraulic type, which permits cyclic thermal movements. During slow cyclic excursions, the snubber exerts no restraint on the piping system. Rapid movement of the piston (caused by a dynamic force) will cause a pressure differential between the ends of the snubber valve piston. This differential is sufficient to close the bypass ports in the valve, making the piston immovable and providing the resistive force. Snubbers are designed for tension and compression.

Limit stops are also used. They perform the same function as a snubber in that they permit cyclic thermal movement. In a dynamic event, Limit Stops 'limit' pipe movement. Limit stops are a passive device and require no piston or piston valve arrangement to activate. Limit stops are designed for tension and compression.

The valves of the high head safety injection system open or close in ten seconds (in contrast to accumulator check valves that open almost instantaneously); therefore, the hydraulic force should present no problem. The relatively slow closure time of these valves should present no water hammer problems.

6.3.3.4 Single Failure Analysis

A single active failure analysis is presented in Table 6.3-1. Credible active system failures are considered. The analyses of the LOCA presented in Section 14 is consistent with the single failure analysis, based on a single failure in the ECCS.

The analysis shows that the failure of any single active component does not prevent fulfilling the design function; also, operator action is not required to correct the malfunction.

In addition to the single active failure capability, an alternate flow path is available through the high head safety injection pumps should any part of the flow path from the low head pumps to RCS cold legs become unavailable. This feature ensures that core cooling would be maintained in the event of a piping failure in the ECCS. It also should be noted that the reactor cold legs are fed via a common header in the injection mode and it is not possible to isolate the broken leg and prevent spilling under the present design.

In the particular case of a pump being out for maintenance, an additional active or passive failure is not considered. The maximum period that operation would be continued with two pumps out for maintenance is specified in the Technical Specifications.

Failure analysis of the emergency power supply under LOCA conditions are described in Section 8.5.

<u>Inadvertent Closure of Normally Open Motor-Operated Valves</u>

The ESF systems are designed to tolerate, without loss of their protective function, a single failure during the period of recovery following an incident such as a LOCA. The period of recovery includes both the injection phase and the recirculation phase. Compliance with the single failure criterion is discussed in Section 6.3.1.2.

In order to assure that the accumulator isolation valves will be open during power operation when availability of the accumulator is required, the valve control circuit has the following features:

1. The valves receive an "open" signal upon initiation of safety injection. Upon receipt of a safety injection signal, the valve is blocked from closing.

2. The valves automatically receive an "open" when the pressurizer pressure exceeds a given pressure (safety injection unblocked).

3. The valves have redundant position indication in the control room (Vertical Board and Bench Board) operated by independent limit switches in the motor operator.

4. The valves have audible alarms, with the alarm circuits actuated by the diverse position sensors in the motor operator and stem mounted limit switches for each valve, to alarm whenever the valve is not fully open and reactor pressure is above a preset value.

5. The audible alarm is timed to reactivate at approximately one hour intervals as long as the valve is not fully open and system pressure is above the preset value.

6. The valve control circuit has power lock out jacks and automatic indication of grounding or shorting of the lock out jack as described below.

Each accumulator isolation valve control circuit also contains a power lock out jack. Removal of the power lock out jack will remove power from the valve actuating contacts, but will permit the operation of the valve position indicating lights.

The power lock out jacks are installed only during plant heat up and cool down. As the plant pressure exceeds a specified pressure, the accumulator isolation valves are opened and the power lock out jacks are removed thus preventing inadvertent closure of the valves. Similarly, the lock out jacks are not installed during plant cooldown until the plant pressure is below specified pressure and the valves are required to be closed. The installation of the power lock out jacks and operation of the valves is covered by the Technical Specifications. The power lock out jack circuits also contain an automatic indication of grounding or shorting of at least one of the two controls in the power isolation jack.

A failure analysis has been done to investigate the probability that such a valve would be closed during the short time required following a LOCA. Using the fault tree technique, the various combinations of equipment faults and human errors leading to spurious valve closure were evaluated and the probability of such an occurrence was determined to be 0.65×10^{-7} per demand for a single valve. Failure rates for the various equipment faults were taken from data in References 1, 2, 3 and 4. Conservative engineering judgement was applied where specific data on identical components in required failure modes were unavailable. Refer to Table 6.3-11 and Figure 6.3-7.

Based on this analysis it can be stated that this situation of spurious valve closure can indeed be considered extremely unlikely.

6.3.3.5 Reliance on Interconnected System

During the injection phase, the safety injection charging pumps are not dependent on any portion of other systems with the exception of the suction line from the refueling water storage tank. During the recirculation phase of the accident for small breaks, suction to the safety injection charging pumps is provided by the low head safety injection pumps. An installed bypass line connects the outside recirculation spray pumps to the safety injection charging pumps. This bypass line is not intended nor is it assumed to function in any design basis event. It serves only as a tool to address beyond design basis events such as multiple LHSI system failures. Administrative control of the locked closed manual valves ensures strict compliance with this intent. (See Figure 6.1-1)

To maintain the containment subatmospheric, spray recirculation and cooling must be continued following a LOCA. Initially spray recirculation is continuous, but as the core residual heat level decreases, the recirculation rate is reduced and, eventually, the system may be operated intermittently.

Since the heat removal from the containment must be accomplished initially through the recirculation spray subsystems and since this represents a more than adequate heat removal mechanism for the containment, the use of heat exchangers in the low head safety injection system for cooling is not required. The low head safety injection system operates to provide long term core cooling with no heat exchangers in the system by using water from the containment sump.

6.3.3.6 Normal/Accident Function Evaluation

Table 6.3-12 is an evaluation of the main components, which have been previously discussed, and a brief description of how each component functions during normal operation and during the accident.

6.3.3.7 Passive Systems

The accumulators are a passive safety feature in that they will perform their design function in the total absence of an actuation signal or power source. The only moving parts in the accumulator injection train are in the two check valves.

The working parts of the check valves are exposed to fluid of relatively low boric acid concentration. Even if some unforeseen deposition accumulated, a reversed differential pressure of about 25 psi would shear any particles in the bearing that tended to prevent valve functioning. This is demonstrated by calculation.

The isolation valve at each accumulator is normally open with power to the motor operator locked out via banana type lock out jack, located on the main control board. Redundant position

The change-over is accomplished by realigning the HHSI pumps to deliver to the hot legs. During the change-over, the LHSI pumps will continue injection to the cold legs.

6.3.4 Inspections and Tests

6.3.4.1 Inspection

Quality standards of safety injection system components are presented in Table 6.3-4.

All components of the ECCS system are inspected periodically to demonstrate system operability.

The pressure containing components are inspected for leaks from pumps seals, valve packing, flanged joints and safety valves during system testing.

6.3.4.2 Tests

Preoperational Component Testing

Preoperational performance tests of the components were performed in the manufacturer's shop. The pressure containing parts of the pumps were hydrostatically tested in accordance with ASME, Boiler and Pressure Vessel Code, Paragraph UG-99. Each pump was given a complete shop performance test in accordance with Hydraulic Institute Standards. The pumps were run at design flow and head, shutoff and head and at additional points to verify performance characteristics. NPSH was established at design flow by means of adjusting suction pressure for a representative pump. This test was witnessed by qualified Westinghouse and licensee personnel.

The remote operated valves in the ECCS are motor or air operated. Shop tests for each valve included a hydrostatic pressure test, leakage tests, a check of opening and closing time and verification of torque switch and limit switch settings. The ability of the operator to move the valve with the design differential pressure across the gate was demonstrated by opening the valve with an appropriate hydrostatic pressure on one side of the valve.

The recirculation piping and accumulators are initially hydrostatically tested at 150 percent of design pressure.

Pre-operational System Testing

After hot functional testing and prior to initial fuel loading, the ECCS was operationally tested. These tests included individual pump full flow tests, accumulator operation and complete system operational flow tests, with the reactor head removed. The purpose of this test was to demonstrate the proper functioning of the instrumentation and actuation circuits and to

evaluate the dynamics of placing the system in operation. Water was supplied from the refueling water storage tank for this series of tests. Actuation of the pressurizer low level and pressure signals initiated the automatic startup of the ECCS.

The operability of the accumulators was checked by closing the stop valve, raising the pressure in the accumulator and then opening the stop valve and observing the accumulator level change to provide indication of system delivery.

For those portions of the ECCS and CVCS containing concentrated boric acid, the preoperational test of the heat tracing system included review of manufacturers' design and field testing of all areas, using thermocouples to verify the adequacy of the installations.

A complete check was also made of the controls and alarms of each redundant circuit.

Tests During Refueling Shutdowns

Testing can be conducted to demonstrate proper automatic operation of the ECCS. The test of the safety injection charging pumps can use the minimum flow recirculation lines which return to the volume control tank and can also be tested at any time during station operation due to their dual charging and ECCS function. A test of the low head safety injection pumps can use the recirculation lines which return to the refueling water storage tank.

The operation of the remote stop valves in the accumulator discharge line are tested by opening the remote test valves in the test line between the remote stop valves and the check valves. Flow through the test line is measured and the opening and closing of the discharge line stop valves is verified by the flow instrumentation. The test line can also be used to check leakage through both the check valves and to ascertain that these valves seat whenever the reactor system pressure is raised.

Since the isolation valves are open with power removed during plant operation, and required periodic surveillances verify that power to the valve motor operators is removed, the valves are open, and no position alarms are present, the possibility of inadvertent closure of the isolation valves is eliminated. Because the valves are energized for only brief intervals to change valve position during startup or shutdown, the automatic features to assure the valves will open when required serve no useful function. Thus, the auto open and blocking of closing on an SI signal and auto open on RCS pressure greater than 2000 psig are not required to be tested.

Testing During Normal Operation

Each active component of the ECCS may be individually actuated at any time during operation of the unit to demonstrate operability.

The CVCS charging pumps serve as the high head safety injection pumps. As such, the operability of at least one pump is demonstrated by continuous charging operation while the unit is at power. Demonstration tests can be performed at other times on the other two pumps while charging with the third by employing the minimum flow recirculation line which returns to the volume control tank.

The tests of the low head safety injection pumps employ the minimum flow recirculation test line which returns to the refueling water storage tank. Remotely operated valves are exercised and actuation circuits are tested during this flow test.

The accumulator pressure and level are continuously monitored during station operation and any RCS leakage past the accumulator check valves can be checked at any time using test lines.

The accumulators, the boron injection tank and the injection piping up to the final isolation valve are maintained full of borated water while the unit is in operation. The accumulators are refilled with borated water from the refueling water storage tank by using the positive displacement hydrotest pump.

The contents of the boron injection tank are continuously recirculated to and from a surge tank by recirculation pumps. The concentration in the accumulators and boron injection tank is checked periodically by sampling.

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15. "ASTM Recommended Practice for Radiographic Testing," ASTM E-94, The American Society for Test and Materials.

16. "ASTM Reference for Radiographs for Steel Castings Up to 2 Inches in Thickness," ASTM E-71, The American Society for Test and Materials.

17. "ASTM Reference for Radiographs for Heavy-Walled [2 to 4 1/2 inch (51 to 114 mm)] Steel Castings," ASTM E-186, The American Society for Test Materials.

18. "ASTM Reference Radiographs for Heavy-Walled [4 1/2 to 12 inch (114 to 305 mm)] Steel Castings," ASTM E-280, The American Society for Test and Materials.

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References for Section 6.3 (Cont'd)

28. "ASTM Specification for Wrought Austenitic Stainless Steel Piping Fittings," ASTM A-403, The American Society for Test and Materials.

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32. The term "Equivalent" is described in UFSAR Section 1.8.2, "Equivalent Materials."

6.4 CONTAINMENT DEPRESSURIZATION SYSTEM

6.4.1 Design Bases

The containment depressurization system is composed of two groups of subsystems: the quench spray subsystems and the recirculation spray subsystems. These systems are designed to provide the necessary cooling and depressurization of the containment after any LOCA.

The subsystems are designed in accordance with 1971 General Design Criteria 38 through 43 of Appendix A to 10CFR50. Operating together, these subsystems cool and depressurize the containment to subatmospheric pressure in less than 60 minutes following the Design Basis Accident (DBA), assuming the operation of at least minimum engineered safety features as defined in Section 14.3

In addition, the recirculation spray subsystems are capable of maintaining the subatmospheric pressure in the containment for an extended period following the DBA.

Equipment in the containment depressurization system are designed according to the code criteria and earthquake criteria specified in Section 6.2 and 2.5, respectively.

6.4.2 Description

The quench and recirculation spray subsystems are sized to satisfy the following design bases:

1. The containment shall be depressurized (returned to below 1 atmosphere pressure) in less than 60 minutes following a LOCA.

2. Once depressurized, it shall remain depressurized after a LOCA.

3. The LOCA to be considered is a double-ended rupture of a reactor coolant pump suction line.

4. The temperature of the RWST is in the range of 45°F to 55°F.

5. The inlet temperature of the cooling (river) water for the recirculation cooler is at a maximum of 90°F.

6. The minimum engineered safeguards configuration (one 360 degree quench spray header and two 180 degree recirculation headers) shall be used.

7. Initiation of a recirculation spray subsystem shall be delayed 300 seconds to ensure adequate water in the containment sumps and to provide high containment back pressures to enhance ECCS effectiveness during reflood.

The function of the sprays is to remove heat from the containment atmosphere by convection and condensation. Heat is transferred out of the containment by means of the recirculation coolers. Table 6.4-2 lists the design parameters for components of the heat removal system.

All parts in contact with the pumped fluids are made of austenitic stainless steel. The tube side fouling factor is assumed to be 0.0003. The shell side fouling factor is assumed to be 0.0002, as the shell will be laid up dry. Any shell side fouling occurring during service is more than compensated for since the heat duty required of the cooler decreases rapidly with time.

The fluid flow paths through a recirculation cooler is shown in Figure 6.4-4.

The tube side and shell side temperatures and flow rates for the recirculation coolers are determined as follows:

1. Recirculation spray water flow rates, river water flow rates, quench spray flow rates and refueling water storage tank capacity are assumed.

2. An overall heat removal capability, UA (Btu/hr/F) is assumed.

3. A parameter study is conducted for the minimum safeguards case using varying assumptions for the variables in 1 and 2 above. Initial containment conditions and maximum river water temperatures are selected to maximize the heat load requirements on the recirculation coolers. For each set of assumptions the shell and tube side temperatures and heat removal rates resulting from these assumptions are available as output from a computer analysis.

4. As a result of the parameter study, a set of recirculation flow rates, quench spray flow rates and the recirculation heat exchanger UA is selected, consistent with emergency diesel loading requirements and depressurization of the containment, as prescribed by the designed bases (Section 6.4.1).

Since the duty requirements and the operating temperature for the recirculation coolers are determined by the LOCTIC code which is capable of considering all the loads imposed on the coolers by depressurization and recirculation, the specifications derived therefrom ensure proper sizing of the recirculation coolers.

Quench Spray Subsystem

Two quench spray subsystems, shown in Figure 6.4-1A, are made up of two separate parallel subsystems, each of 100 percent capacity.

Each of these subsystems draws water independently from the refueling water storage tank and supplies it to a quench spray header located inside the containment. In addition, quench spray water is also directed to the suction of the outside and inside recirculating water spray pump at a flow rate of 300 gpm and 150 gpm respectively. A restricting flow orifice in parallel with a motor-operated cut back valve has also been installed downstream of each quench spray pump to provide reduced flow for subatmospheric peak pressure control. Upon a RWST low level signal, the motor operated cut back valve closes and directs water through the flow orifice to provide a flow rate of approximately 1,100 gpm at the spray nozzles. Component design data for the quench spray subsystems are given in Table 6.4-1.

During preliminary design of the containment spray subsystem, it was assumed that the quench spray pumps became effective 60 seconds after receipt of a containment isolation phase B signal. The quench spray delay was intended to provide time for diesel generator startup, pump startup, discharge valve opening time and piping fill time. Analysis of the quench subsystem showed that approximately 64 seconds was required from beginning of pump startup to achieve rated flow through the nozzles.

In addition to the cooling and depressurization function of the containment depressurization system, sodium hydroxide (NaOH) solution is added to the quench spray from the chemical addition tank to improve removal of radioactive iodine from the containment atmosphere (Section 14.3). Addition of the sodium hydroxide solution from the chemical addition tank occurs whenever the chemical addition components are energized by a containment isolation phase B signal. Two redundant chemical addition lines, each containing two positive displacement pumps with electric motor drivers and a motor operated discharge isolation valve supply a sodium hydroxide solution to the suction of the quench spray pumps (see Figure 6.4-1A). The quench spray will have a pH of at least 8.5 (maximum pH 11.0) while the chemical addition tank (CAT) is emptying. The earliest the CAT can empty is 55 minutes. After this, the quench spray is borated water from the refueling water storage tank. In the case of a chemical addition valve failing closed, the CAT takes about 110 minutes to empty.

Depending on the draw-down rate of the RWST (i.e., whether minimum or normal engineered safety features or other pumping combinations are in effect), the pH of the spray from the quench spray header into the containment can vary from 8.5 to 11. The final pH in the containment after a DBA including the contents of the RWST is approximately 8.0.

A piping loop seal has been added to each of the quench spray flow paths. This prevents water in the RWST from draining into the containment sump, if after a LOCA a quench spray pump is not in operation and the valves along the flowpaths are open. A small hole is drilled in the high point of each loop seal to act as a system break.

The Chemical Addition Tank (CAT) is fabricated of ASTM A240,[5] Type 304 stainless steel or its equivalent.[6] It is maintained at a minimum level of 4700 gallons of a 19.5 to 20 percent by weight sodium hydroxide solution. Heat tracing circuits and level instrumentation with appropriate alarms and powered from emergency power buses ensure that the chemical addition tank is ready for use in the event of a LOCA and that it can be monitored effectively during a LOCA.

The two chemical injection subsystems are electrically redundant and independent, since only one loop of the chemical injection subsystems is needed to perform the necessary safety function, the single failure criteria is adequately addressed. The chemical injection pumps will automatically stop on low quench spray system flow, or motor overload. The capability to manually start or stop the chemical injection pumps is bypassed by the CIB signal. One chemical injection pump per loop will stop on a signal from the cutback control valve in the quench spray loop provided that the other chemical injection pump is running and no automatic stop signals, mentioned above, have occurred. Pump running or not running indication is provided in the control room. There is no local control station outside the control room for operation of these pumps.

The design of the refueling water storage tank (RWST) and the CAT will ensure adequate negative reactivity and cooling water addition to the reactor core and ensure a caustic flow to the quench spray headers inside containment for all possible draw down rates of the RWST.

The ultimate pH of the containment sump is determined from the boric acid concentration of the reactor coolant system, RWST, boric acid addition tank and the three safety injection accumulators, plus the addition of caustic from the CAT by means of the quench sprays.

No provisions for monitoring or adjusting the pH of the sump water are necessary. The only way in which the pH of the sump water could be altered would be leakage of river water at the recirculation coolers. This is prevented by maintaining the recirculation water pressure greater than the river water pressure. Any possible radioactive outleakage through a heat exchanger would be detected by the use of the four recirculation spray heat exchanger river water radiation monitors.

The RWST is a vertical cylindrical tank with flat bottom and hemispherical top, mounted on and secured to a reinforced concrete foundation. Maximum tank volume is approximately 441,000 gallons. The tank is fabricated of ASTM A-240, Type 304L, or equivalent,[6] stainless steel plates. Operational parameters for the RWST are provided in the Technical Specifications. The chemical addition tank is a vertical cylindrical vessel with flanged and dished heads mounted on a skirt and secured to the reinforced concrete foundation.

The water in the RWST is cooled prior to initial unit startup, during unit operation, and following refueling operations, to a temperature corresponding to the requirements of the Technical Specifications by circulating it through a heat exchanger which uses chilled water to remove heat. The tank is insulated to limit the temperature rise of the water to 1/2°F or less per 24 hour period. During normal plant operation, after the water in the tank has been cooled initially by the RWST coolers, it is maintained at the required temperature by circulation through either of two mechanical refrigeration units. Freezing in the RWST during cold weather periods is prevented by the RWST insulation and by maintaining the RWST temperature above the minimum temperature specified in the Technical Specifications. Heat tracing is provided on all lines exposed to the weather.

During normal operation, RWST water may be processed through the fuel pool cooling and purification system to meet water chemistry requirements and/or to reduce radiation levels.

The tank is provided with a manhole for access into the tank for inspection during the refueling periods.

The tank is designed as a Seismic Category I component to withstand design seismic loadings. An evaluation is made to establish that there is no loss of function following the design earthquake conditions. The connecting piping is also designed to withstand seismic loading, to ensure the functioning of the system.

Figure 1.2-1 shows the refueling water storage tank (RWST) in relation to adjacent facilities. The following protective measures have been taken to prevent the tank from being functionally degraded by missiles generated by rotating equipment, fires, explosions and the failure of adjacent nonseismic structures:

1. The RWST has concrete shielding completely surrounding the tank to El. 762 ft 6 inches. The only rotating equipment in this area are the chemical addition tank pump and the chemical injection pumps. The concrete shielding around the RWST will provide adequate protection against damage from failure of the rotating equipment.

2. Degradation of the RWST from fires is considered highly unlikely. The transformer located west of the RWST has a sprinkler system provided to handle accidental fire. No combustible materials are stored in this area. The concrete shielding, metal covering and insulation provide protection of the tank from fire.

3. The nonseismic structures in the vicinity of the RWST are the service building and warehouse. These structures

will collapse in place during a seismic disturbance. The distance from these structures and the concrete shielding provides adequate protection.

Lines connected to the RWST that are essential in attaining and maintaining a safe shutdown during accident conditions are 12"-SI-1-153W-Q3, 12"-QS-1-153B-Q3 and 12"-QS-2-153B-Q3. All essential piping from the RWST is routed through missile protected pipe trenches before entering the safeguards or the cable vault structures. All lines in unheated spaces have insulation and heat tracing provided to prevent freezing of the pipes. All lines connected to the RWST have valves that can be either manually or remote manually closed in case of line rupture. Redundant level alarms in the main control room will annunciate when water level drops below normal liquid elevation.

Each quench spray pump alone is capable of supplying about 2,000 gpm of borated water to separate 360 degree quench spray ring headers located approximately 96 ft. above the operating floor in the curved section of the dome. The quench spray ring headers have a centerline diameter of about 67 ft. and a total of 196 nozzles per header.

Each of the quench spray headers has 118 Spraying Systems Co. Type 1/2-B40 nozzles. These nozzles produce a relatively fine hollow cone spray pattern. These nozzles are positioned to spray downward and have a spray angle of 70-80 degrees. There are also 40 quench spray nozzles that are plugged on each header. The remaining 78 nozzles, on each quench spray header, are Spraying Systems Co. Type 1713A nozzles. These nozzles are positioned to spray upward at an angle of 22.5 degrees from horizontal. The spray nozzles are positioned so that there are two nozzles side by side with a 10.75 inch distance between them. A 21.5 inch space is then provided on the header before the next two nozzles are located. This symmetrical configuration is utilized the entire distance of the quench spray header.

The mean equivalent diameter of the quench spray droplets is less than 1,000 microns. The quench pumps are located adjacent to both the containment structure and the RWST. Each quench pump discharge line contains a weight-loaded check valve inside the containment. One-half inch drain lines are located immediately after the check valves to provide for draining the quench spray risers should any waste enter the risers during periodic testing. The small drain line does not noticeably decrease the capacity of the quench spray during operation. A stainless steel strainer is provided in the discharge of each quench pump.

The quench spray pumps shall be flow tested at the frequency specified in ASME Section XI. A deviation from flow rates and discharge pressures, as previously determined during preoperational tests, will indicate either particulate buildup in the strainers or clogging of the test spray nozzles (smallest

size nozzles orifice) in the refueling water storage tank. Strainers and test nozzles are easily removable if cleaning is required. The strainers located on the discharge of the quench spray pumps have a 4 mesh per inch (0.063 inch diameter wire) outer basket and a 20 mesh per inch (0.014 inch diameter wire) inner basket.

Recirculation Spray Subsystem

Each of the four recirculation spray subsystems, shown in Figure 6.4-1B, consists of a recirculation pump and a recirculation spray cooler and feeds a 180 degree spray ring header located approximately 80 ft above the operating floor. Component design data for the recirculation spray subsystems is given in Table 6.4-2. The recirculation spray pumps become effective automatically 5 minutes after receipt of a containment isolation phase B signal (Section 7.5). The total delay of 300 seconds in the recirculation spray effective time was selected to provide maximum containment pressures during core reflooding after a cold leg DER. For the recirculation spray subsystem, from approximately 65 to 83 seconds is required to fill the system piping and deliver rated flow. Timers installed in the recirculation spray pump start circuitry are set at approximately 210 seconds for pumps 1RS-P-1A and 1RS-P-2B and at approximately 225 seconds for pumps 1RS-P-1B and 1RS-P-2A. Analysis has shown that 60 second changes in the times at which the quench spray system and/or recirculation spray system are taken to be effective have little or no effect on the containment depressurization time or the ability to remain depressurized.

Two of the recirculation spray ring headers have a radius of 49 ft-3 inches. The other two have a radius of 50 ft-3 inches. Each of the headers has 195 fittings for spray nozzles, with each fitting having two spray nozzles. Ninety-eight of these fittings have two Spraying Systems Co. Type 1/2-B60 nozzles. These nozzles are similar to the quench spray 1/2-B40 nozzles in having a relatively fine spray, but have a larger orifice. One nozzle per fitting is positioned to spray vertically downward while the other is positioned to spray horizontally toward the center of the containment.

Each of the remaining 97 fittings per header is equipped with one Spraying Systems Co. Type 1/2-B60 nozzle and either a Spraying Systems Co. Type 1713A nozzle or a plug. Per header, there are 64 Spraying Systems Co. Type 1713A nozzles and 33 plugs. The 1/2-B60 nozzle is positioned to spray horizontally toward the center of the containment while the 1713A nozzles are positioned to spray upward at an angle of 45 degrees to the horizontal toward the center of the containment. The 1713A nozzles on the lower headers are provided with 9 inch extensions so that the spray can clear the upper header. The two nozzle arrangements are positioned alternately on each recirculation spray ring header. The mean equivalent diameter of the recirculation spray droplets is less than 1,000 microns.

The four recirculation spray pumps take suction from the containment sump, which is enclosed by a protective screen assembly. The assembly consists of three sections, the inclined bars and two stages of screening. The inclined bars act as trash screens to prevent large pieces of debris from reaching the roughing and final screens. After the bars, there are two stages of screening, the first consisting of a coarse mesh and the second a fine mesh with an opening slightly smaller than the size of the smallest nozzle orifice in the recirculation spray header. The assembly is divided at the center line by screening so that failure of either half does not adversely affect the other half.

Each half of the assembly has an area of about 65 sq ft for a total screen area of approximately 130 sq ft. Each pipe suction point is equipped with a screen cap extending from the containment liner to the top of the large screen assembly with an area of approximately 47 sq ft. Figure 6.4-2 shows the bar and screen arrangement to be used. The location of the screen caps above, as well as below, the floor level makes it difficult for them to be blocked by debris.

The mesh size of the final (rough) screen size is 1.33 square mesh, 6 gage wire screen. The intermediate (fine) screen caps over the recirculation spray pump suction points are 4 square mesh 16 gage wire.

Each recirculation spray pump suction is also equipped with anti-vortexing devices. These devices consist of:

1. two layers of horizontal grating covering the sump plan area made from 3 inch x 1/8 inch steel bars and

2. the two inside recirculation spray pumps have perforated guiding vanes over their wells and around their casings while the two outside recirculation spray pumps have cruciforms of perforated plate. The perforations on the vanes and cruciform plates are 1/4 inch diameter at a distance of 3/8 inch center to center.

Two of the recirculation spray pumps and associated motors are located outside the containment and two pumps and motors are located inside the containment. The four pumps are of the vertical deep-well type. The outside pumps have shaft extensions to permit locating the pump suctions at a level below the containment sump, with the motors at an elevation slightly above grade. Each pump has a capacity of approximately 3,300 gpm.

The recirculation spray pump motor supports are located at El. 702 ft 10 5/8 inch inside containment. The maximum post accident water level in the containment is at El. 698 ft 9 inch.

The recirculation spray pump motors have been selected to ensure their operation under accident conditions.

The outside recirculation spray pumps are fitted with a tandem mechanical seal arrangement. The tandem mechanical seal arrangement provides a positive seal against leakage of radioactive fluid from the seals of the outside recirculation spray pumps. The seal arrangement also provides adequate lubrication and cooling for the seals. Level alarms are provided to ensure that adequate accumulator water volume is available and to indicate the failure of either seal.

The seal arrangement consists of two mechanical face seals (Items No. 2 and No. 7), arranged to enclose a non-radioactive seal fluid. After the pump is started, the pressure between the seals is maintained higher than the pressure outside either seal by an accumulator with a weight loaded diaphragm. The accumulator is fitted with two sealed level switches and alarms for annunciation in the main control room. The seal fluid is cooled by being pumped by the pumping ring (Item No. 6) through an air cooler. The accumulator is conservatively sized to allow for sufficient volume of demineralized water outleakage during operation of the pump.

The total volume of the seal water system accumulator is 2.6 gallons. The volume in the lower section of the seal chamber between level alarms is 1,085 ml. The normal outleakage rate, obtained from Crane Packing Company, is 0.26 ml per hour. Based on the normal outleakage rate and the volume of the lower section of the accumulator between level alarms, the recirculation spray pump could be operated for 5.8 months without requiring a supply of makeup water to the accumulator. A seal water accumulator low level alarm at this point will warn the operator of the pending loss of seal water (1.75 months remaining of seal water). A valved hose connection is provided on the seal piping in order to fill the accumulator and associated piping from nearby demineralized water hose connections. Operating the pumps without seal water will cause eventual seal failure and subsequent loss of radioactive fluid to the safeguards area. However, a recirculation spray pump will not be operated without seal water. Twenty-four hours after a DBA only one recirculation spray pump is required for intermittent operation in order to remove decay heat being generated in the reactor core to maintain subatmospheric conditions in the containment. Sufficient time is available to allow for refill of one outside recirculation spray accumulator or use of one of the other three recirculation spray pumps.

The seal water accumulator and piping are constructed of stainless steel and designed for service at peak operating conditions. The accumulator is designed to ASME Boiler and Pressure Vessel Code, Section III, C.

The space between the seal faces is maintained at a pressure greater than the recirculation water with demineralized water as seal fluid, thus preventing leakage of the recirculation water, which may be radioactive.

The recirculation water flows through recirculation spray coolers, where it is cooled by river water (Section 9.9) flowing at approximately 4,000 gpm per cooler.

The entire containment depressurization system is constructed of corrosion resistant materials, primarily stainless steel. However, other materials are used where suitable, such as brass for the quench spray nozzles. The system has a 150 psig design pressure.

6.4.3 Evaluation

The containment depressurization system consists of two 100 percent capacity quench spray subsystems and four 50 percent capacity recirculation spray subsystems. The use of separate spray headers on the discharge of each pump allows for the selection of spray nozzle sizes (0.516 inch, 0.360 and 0.375 inch) to give optimum combination of small spray particles for maximum heat transfer and larger particles for better coverage toward the center and sides of the containment.

The components of the containment depressurization system have been selected so that the conditions of service (pressure, temperature and fluid composition) do not prevent the system from performing its intended function.

The methods of preventing the plugging of spray nozzles in the two systems differ. For the quench spray subsystems, the materials of construction, as well as the pump discharge strainer, prevent nozzle plugging. A method of nozzle testing is provided in the refueling water storage tank to ensure that no particulates which could plug the quench spray nozzles collect in the refueling water storage tank. A temporary strainer is provided in the quench pumps suction piping for initial system cleanout. Despite this and regardless of screen opening, some type of particle could conceivably pass lengthwise through the screen and cause clogging of a spray nozzle. However, since the final screen opening is smaller than the smallest spray nozzle size, which is 0.360 inch, such an occurrence is considered to be highly improbable. For the recirculation spray subsystems, the screen assemblies in the containment sumps are arranged so that no single failure could result in the clogging of all suction points (Section 6.4.2) to the recirculation spray subsystems. A main screen assembly failure, coupled with the plugging or failure of the suction point caps, must occur for any one of the suction points to be lost. Sufficient area has been provided to ensure that system operation during accident conditions is not impaired and entrance flow velocities are low enough to prevent entrainment of most small particles. System overdesign allows for some plugging or loss of function, in spite of the foregoing.

Consideration has been given to the possibility of a reaction between sodium hydroxide and atmospheric carbon dioxide forming a precipitate in the chemical addition tank. If the temperature of

the gas space in the tank varies over a range of 60°F each day and all the carbon dioxide which enters due to this breathing reacts, 90 years would be required to react with 1 percent of the stored caustic. The sodium carbonate formed by this reaction would remain soluble at 45°F.

During normal unit operation, the recirculation spray coolers are dry on the shell side and filled with river water with corrosion preventatives on the tube side as described in Section 9.9.2. For long term operation, on the order of weeks, there may be some fouling of the tubes on the river water side, with resultant loss in heat transfer capability. The loss of heat transfer capability will be more than offset by the decrease in necessary heat load due to decreasing decay heat production. One day after a loss-of-coolant accident, the drop in decay heat is such that one pump and heat exchanger has sufficient heat-removal capacity to hold the containment depressurized. With an expected maximum river water temperature of 90 °F, the recirculation spray subsystem design is conservative, with a minimum 100 percent backup capacity at the onset of an accident. Within one day after the LOCA, the backup capacity exceeds 400 percent.

The recirculation spray coolers have welded construction at all points where there is a potential for leakage of radioactive recirculation water into the river water. The maximum pressure differential which can occur between the river water and the recirculation water is 150 psi; under these conditions, leakage flow from the recirculation spray subsystems is toward the river water system. The river water is monitored for leakage by means of radiation monitors. The defective subsystems are shut down if leakage above the allowable values (within the limits of 10CFR20) is detected.

During normal plant operation, a maximum pressure differential of 155 psig (164.7 psia vs. 9.7 psia) exists between the recirculation spray coolers' river water/tube side waterboxes and the external subatmospheric containment. This differential decreases to 116.7 psig during peak DBA conditions. The original recirculation spray coolers have welded diaphragm seal plates installed under the waterbox covers to prevent leakage of nonborated water into the containment sump. When the 1B and 1D recirculation spray coolers were replaced, the new waterbox cover seal design incorporated double (concentric) gasket seals instead of the welded diaphragm seal plates of the original design. Leakage of nonborated water through the gasket seals and into the containment sump was considered. Any leakage through the gasket seals is expected to be negligible. An evaluation of gasket seal leakage concluded that even if a gasket seal failure were to occur, it would not significantly affect cold shutdown margin by boron nor the mitigation of radiological consequences following a postulated DBA.

The recirculation spray coolers low point piping or shell drain valve caps have 1/8 inch holes to permit drainage of any liquid buildup, thereby eliminating any stagnant boric acid and potential stress corrosion cracks. The addition of 1/8 inch holes to the recirculation spray coolers drains has been analyzed and determined to have no effect on the spray function of the recirculation spray system.

Because two of the recirculation spray pumps and associated valves and piping are outside the containment, a potential danger of radioactive leakage exists. Valves have been selected to reduce this leakage potential to a negligible amount. To protect against large leaks the following is done:

1. On the discharge of the recirculation spray pumps, gross leaks are detected by variations in the pump discharge pressure readings in the main control room.

2. Large leaks in the suction piping in the safeguards area are detected by liquid level measuring devices. The floor of the safeguards area is provided with baffles, dividing the floor into two sections. Thus, leakage from recirculation suction lines is detected by the increased liquid level on the affected section of the floor. Upon detection, the operator in the main control room remote-manually isolates the leaking pipe, leaving three recirculation loops operating. In the case of small leaks, detection and isolation of leaks are not possible; however, the gaseous contents of the structure (Figure 6.4-3) enclosing the piping outside the containment are normally discharged to the atmosphere via the elevated release point in the supplementary leak collection and release system (Section 6.6).

Consistent with letters from the ACRS[1] concerning vital piping which must function during a LOCA, passive failure of the recirculation spray pump suction piping during a LOCA is not considered credible during the injection phase of the LOCA. However, if a passive failure in the suction piping upstream of the isolation valve occurs after containment depressurization to subatmospheric pressure has been achieved, the special enclosing valve pit floods with recirculation water providing a water seal which prevents inleakage of outside air into the containment and subsequent return of the containment to atmospheric pressure.

The valves located in the safeguards valve pit area are the outside recirculation spray pump suction isolation valves, outside recirculation spray bypass isolation valve and the low head safety injection pump suction isolation valves.

The safeguards area suction valve pit is shown in Figure 6.1-1 and in Figure 5.1-5 at El. 687 ft-11 inches. Valve operators are located at El. 747 ft in the safeguard area structure. Valve extensions are totally enclosed and water tight.

flooding is initiated. The sensible energy introduced with the core recirculation flow is sufficient to provide mixing within the subcompartment and provide additional driving forces to mix the contents of the subcompartment with the contents of the bulk containment through natural circulation (buoyancy) effects. The subcompartment-to-bulk containment mixing obtained in this manner is several hundred times that required to prevent accumulation of a four volume percent hydrogen mixture in the subcompartment. Table 6.4-5 presents results of calculations showing the amount of energy added, energy removed and induced flow rate in the subcompartment having the DBA.

Minimum sizes used for the calculation for the upper vents (in addition to the floor drain vents) are:

1. Steam generator cubicles 350 ft^2

2. Pressurizer cubicle 40 ft^2.

A failure mode analysis for the components of the containment depressurization system is included in Table 6.4-3.

The air recirculation cooling system may be used to limit the buildup of pressure in the containment structure for small reactor coolant system (RCS) and steam line leaks which are not sufficient in magnitude to automatically initiate operation of the containment depressurization system.

The containment depressurization system is automatically initiated upon receipt of a containment isolation phase B signal. The operator does not have the option of preventing the actuation of containment spray system through the use of the air recirculation cooling system.

Portions of the containment depressurization system can be bypassed for testing.

Containment depressurization system pumps and valves are assigned to ESF actuation slave relays and are tested as described in Section 7.3. Assignments of the containment depressurization system components to these relays, which are individually tested one at a time, are made so that the containment depressurization is not inadvertently initiated due to testing and also so that redundant devices remain functional during the testing.

Post test requirements followed to ensure availability for activation for the components grouped on common test-table relays are established in approved BVPS test procedures.

The requirement for performance of these tests is that minimum engineered safety features are available at all times during testing.

Electrical interlocks which prevent the operator from tripping the spray pumps inadvertently or prematurely from the main control room are accomplished by use of a control switch trip action blocking contact. Upon the receipt of a containment isolation phase B signal, a contact from the pump motor starting timer produces this signal instantaneously.

The containment spray pumps suction and discharge valves are protected from inadvertent closure by a control room operator during pump operation by either a normally closed pump switchgear auxiliary contact placed in the closing circuit of the motor-operated valve, or by access covers placed over the benchboard control switch.

To deactivate any containment spray pump would require two operator actions: (1) manually reset the containment isolation phase B train signal associated with the equipment and (2) place the control switch for the pump in the stop position.

Above the operating floor (El. 767 ft-10 inches), the quench sprays cover a volume of approximately 501,630 cu ft and the recirculation sprays cover a volume of approximately 709,050 cu ft. The total free volume above the operating floor is 1,028,000 cu ft. Because of the forced circulation set up by the sprays, the entire volume above the operating floor is considered to be uniformly mixed and scrubbed by the sprays.

Below the operating floor, the quench sprays cover approximately 407,500 cu ft and the recirculation sprays cover approximately 656,000 cu ft. The total free volume below the operating floor is 768,300 cu ft.

All of the subcompartments, with the exception of the volume below the reactor vessel, the refueling cavity and the incore instrumentation passage, are well vented and scrubbed by the sprays. The following regions are not directly covered by sprays:

Region	Area (cubic ft)
Incore instrumentation passage	6,500
Volume below reactor vessel	2,000
Volume below refueling cavity	21,750

Note that this volume is a portion of the base mat floor. As such, it has no side walls, is not enclosed and is subject to good mixing with the main spray volume.

The spray patterns for the quench and recirculation sprays are depicted in Figure 6.4-8. These spray patterns are based on minimum engineered safeguards.

6.5 POST DBA HYDROGEN CONTROL SYSTEM

6.5.1 Hydrogen Recombiner and Purge System

6.5.1.1 Design Basis

The design basis for hydrogen generation is presented in Section 14.3.4.4. Two 100 percent redundant hydrogen recombiner systems are provided to maintain the hydrogen concentration within containment at a safe level following a Design Basis Accident (DBA).

Use of the recombiner system can maintain the hydrogen concentration in the containment atmosphere below 4 volume percent following a DBA. This complies with the design criteria set forth in AEC Safety Guide 7, "Combustible Gas Concentration and Contamination Following Loss-of-Coolant Accident" (Section 1.3).

The use of aluminum within the containment structure is limited as much as possible, minimizing hydrogen generation due to corrosive alkaline attack following a LOCA. Zinc is used extensively, but is a secondary source of hydrogen compared to all other potential sources. A listing of the aluminum usage in the containment is given in Table 14.3-9.

The entire hydrogen recombiner system is housed in the safeguards building. This system and building are Seismic Category I.

Each recombiner system is designed to handle 50 scfm of containment atmosphere recycling gas to the containment. Two recombiner systems, each independently capable of meeting the specific performance requirements, are designed, fabricated and mounted on skid mounts with pipe flange connections for the inlet and return lines. The control cabinets for the recombiners are floor mounted and are accessible from a front door maintenance panel. Interconnecting plug-in cables of 50 ft. connect the power and control cabinets to the skid-mounted recombiners. Recombiner startup annunciation is provided to the control room.

In the event of failure of the blowers, electric preheater or thermal recombiner following a DBA, the second redundant train would be placed in operation.

Each hydrogen recombiner unit is powered from a separate vital electrical train (orange or purple) and all instrumentation and control equipment associated with one unit is identical to, but separate from the redundant components associated with the second unit.

In regard to IEEE 279-1971, it is noted that the recombiners are manually initiated (vice automatically) following the DBA as discussed in Section 14.3.4.4. In addition, Atomic International has provided a report[3] which has been authorized[4] by the AEC as an acceptable reference in license applications for nuclear power plants.

The hydrogen recombiner units were upgraded to meet the requirements of IEEE-323-1974[8] and IEEE-344-1975[9] by participation in the vendor's generic qualification program.

The hydrogen recombiners are located in the general area at El. 751 ft. of the missile-proof extended safeguards area. The monitoring equipment for the recombiners is also located at El. 751 ft. of the safeguards area and is biologically shielded from the recombiners. Refer to Figure 5.1-1 for indicated locations of equipment.

At the time BV-1 was designed two hydrogen recombiners and a hydrogen purge system were provided to control the hydrogen concentration in containment following a DBA. It was expected that the hydrogen recombiners would be shared between BV-1 and BV-2; however, since that time additional recombiners have been purchased and installed at BV-2. Each unit now has two dedicated hydrogen recombiners to provide the necessary redundancy; therefore, the containment hydrogen purge system at BV-1 is no longer required as a backup to the hydrogen recombiners. Administrative controls required isolation of the containment hydrogen purge system. Isolation of the containment hydrogen purge system ensures that following the DBA this release path is not available to contribute to offsite doses.

The post DBA hydrogen control and purge system is shown in a simplified manner in Figure 6.1-1.

6.5.1.2 System Design

The recombiner units draw the containment atmosphere through two individual open taps located at the top of the containment. These are the same taps used as inlets for the containment vacuum pumps under normal operating conditions (Section 5.4.2).

Each hydrogen recombiner system includes flow control capability, a blower, a temperature controlled electric heater, a thermal recombiner (reaction chamber) and an air blast exchanger. Each recombiner unit is mounted on a single skid. The control console panels are located adjacent to the recombiner units. A multi-conductor instrument cable is provided to connect the electrical heaters, blowers and recombiner instrument lines to the control console.

A summary of performance characteristics for the recombiner is provided in Table 6.5-1.

For system operation, the valves which isolate the system from the plant are opened, the blowers are turned on and the gas flow is greater than or equal to 50 scfm. All temperature controls and limits are preset. A switch is then actuated and the gas temperature is raised by the heater to the preselected control temperatures.

The gases react in the reaction chamber and, as the gas temperature in the reaction chamber approaches a preset point of 1,300°F, the gas heater automatically reduces its power demand to maintain that preset temperature. For example, for a 4 percent hydrogen in air mixture and a preset reaction chamber gas temperature of 1,300°F, the heater outlet gas temperature is reduced to about 730°F. The reaction chamber operates stabilized under even lower inlet temperature conditions. The 570°F rise in gas temperature occurring in the reaction chamber is caused by the heat liberated from the exothermic hydrogen-oxygen reaction. The system then continues to operate automatically, with the heater power gradually increasing as the hydrogen and oxygen gases are depleted, maintaining the same preset reaction chamber temperature. The gas flow out of the reaction chamber is cooled by an air blast heat exchanger and returned to the containment at 150°F.

Design operation of the recombiner system is dependent on the availability of the containment vacuum system piping within the containment and power from the emergency diesel generators.

6.5.1.3 Evaluation

An evaluation of the post DBA hydrogen control system is presented in Section 14.3.4.4.

6.5.1.4 Testing and Inspection

Testing of the hydrogen control system is performed in accordance with Technical Specifications. During these tests, after the blower is in operation, the inlet from the containment is opened and the containment atmosphere is allowed through the system. A flow slightly greater than 50 scfm is verified. Normal design function of the various components together with a satisfactory temperature rise through the thermal recombiner indicates proper operation of the system.

During testing of the hydrogen control system, no biological shielding is required and contamination is negligible. For system operation after a postulated DBA, inside surfaces will become contaminated with fission products. However, all internal surfaces of high temperature components are smooth, and gas velocities are relatively high. Therefore, fission product buildup or holdup will be minimal and decontamination of the smooth stainless steel components will be relatively simple.

The major gamma source requiring personnel shielding or isolation during operation after the postulated DBA is fission products decay in the process gas stream. The total system volume is only approximately 3 cu ft and the residence time of the gas in the recombiner system is about 1 second. When the system is cold, the flow residence time is about 3 seconds.

6.5.1.5 Instrumentation

The gas temperature of the reaction chamber is controlled by thermocouple signals feeding back to the Silicon-Control-Rectifier (SCR), power controller which regulates power to the electrical heaters.

Temperature switches with pre-determined setpoints are used as heater protective circuits which open the heater power circuit breaker when the setpoint is exceeded. The breaker automatically closes when the overtemperature condition is corrected.

6.5.1.6 Materials

The process equipment in the recombiner package is constructed of Type 304 or 316 stainless steel except for the carbon steel canned blower vessel. Their high temperature sections were insulated and all insulation is covered by a breathing, weather-proof, carbon steel shell not less than 3/16 inch in thickness. All carbon steel components including the structural steel skids were painted, as required. The exposed valves, flowmeters and end connections were capped and sealed for shipment and storage. All wiring was in sealed junction boxes and conduits. Therefore, all of the components in the recombiner package were considered to be weatherproof.

The Inconel-clad heating elements operate under rated conditions with sheath temperatures always less than 1,600°F. Few heater failures over the 40 year life are expected. A number (about 30 percent) of heating elements could fail before the system would cease to function. However, failed heating elements can be readily removed and replaced from their exposed cold end.

Following installation, periodic operating tests verify readiness of the system to perform its function. These tests should show that all components are operable, that the blower provides adequate gas flow and that the heaters raise gas temperatures to their predetermined control setpoints. Between these periodic tests, the following simple procedures will be carried out to assure that no significant corrosion of the stainless steel system occurs. Trickle heaters are continuously energized to prevent condensation from accumulating in the recombiner units.

6.5.1.7.10 Hydrogen Analyzers

The Unit 1 narrow range hydrogen analyzers have been retired in place, based on the use of the wide range hydrogen analyzers (Section 6.5.2, Containment Hydrogen Analyzer System) in lieu of the narrow range hydrogen analyzers.

6.5.2 Containment Hydrogen Analyzer System

The containment hydrogen analyzer system consists of two redundant hydrogen monitors energized from separate Class 1E Power supplies to provide protection against single failure and single loss of power. Containment samples are obtained through independent sample lines for each monitor. Indication is provided for each hydrogen analyzer, on the vertical board in the main control room, with an indicating range of 0-10 percent hydrogen. A recorder is provided to record the Train A hydrogen level. The hydrogen analyzer system is designed to provide a continuous positive indication of the containment hydrogen concentration within 30 minutes after the initiation of safety injection. The containment hydrogen analyzer system was added as a requirement of an NRC Order[11] in response to NUREG 0737 TMI Issue II.F.1.

The hydrogen analyzer units are located in the cable vault areas (Train "A" in the west cable vault and Train "B" in the east cable vault). The hydrogen analyzer units are of the thermal conductivity type. Each hydrogen analyzer has sampling lines running to two containment locations. One sample line from each analyzer connects to a dome snorkle line which runs to the top of the containment dome. The second sample line for each analyzer runs to a location high within the pressurizer cubicle. Each of the four sample lines contains silver zeolite filters which remove iodine from the air sample prior to leaving containment. All sample lines are sloped to loop seal drains which allow condensate to drain while preventing air from being drawn in through the drain. Each analyzer has one line for returning samples to containment. There are two normally closed (fail closed) solenoid operated valves on each sample and return line. One valve is located in containment and the other outside containment in the cable vault. The solenoid valves are remotely operated from the main control room with key switches. Valve position indicating lights (open/closed) are provided for each solenoid valve.

The analyzer control panels located in the switchgear area contain supporting electronics, signal conditioning, digital readouts, recorder outputs, caution and high alarm setpoint controls, span gas controls, zero and span adjustments and main system power controls. Span gases are supplied directly to the analyzers to allow for periodic calibration of the units.

Reference for Section 6.5

1. "IEEE Criteria for Protection Systems for Nuclear Power Generating Stations", IEEE-279-71, The Institute of Electrical and Electronic Engineers.

2. Reference deleted by Revision 5.

3. "Hydrogen Recombiner for Post LOCA Application", AI-73-27 (Proprietary), Atomic International.

4. AEC Letter to Atomic International dated January 7, 1974.

5. "ASTM Specification for High-Strength Low-Alloy Structural Steel", ASTM A-242-63, The American Society for Testing and Materials.

6. "ASTM Specification for Seamless and Welded Austenitic Stainless Steel Pipe", ASTM A-312-64, The American Society for Testing and Materials.

7. "ANSI National Electrical Code", ANSI Cl-71, The American National Standards Institute.

8. "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations", IEEE-323-1974, The Institute of Electrical and Electronic Engineers.

9. "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generation Stations", IEEE-344-1975, The Institute of Electrical and Electronic Engineers.

10. The term "equivalent" is described in UFSAR Section 1.8.2, "Equivalent Materials."

11. S. A. Varga, Jr. (USNRC) BVPS-1 Order Modifying License, letter to J. J. Carey (BVPS) (July 10, 1981).

6.6 SUPPLEMENTARY LEAK COLLECTION AND RELEASE SYSTEM

6.6.1 Design Bases

The supplementary leak collection and release system is designed according to the following criteria:

1. The maintenance of 0.125 inch water gauge negative pressure in most areas contiguous to the containment (with the exception of the main steam valve area, the steam generator blowdown room, the purge air duct area, east cable vault and west cable vault), containment during refueling, the waste gas storage area and the fuel building.

2. The filtration by impregnated charcoal of contaminated air for radioactive iodine removal with individual charcoal cells sized for 600 cfm.

3. The discharge of exhaust air at the SLCRS Vent.

4. The use of redundant filter banks and exhaust fans with the fans operable on emergency power.

5. Equipment and system capability of withstanding the design basis earthquake without loss of function.

6. Removal of heat from areas containing safety related equipment following a design basis accident with loss of offsite power.

6.6.2 Description

The elements of the supplementary leak collection and release system are shown in Figure 6.6-1. The design data is provided in Table 6.6-1.

The primary function of the system is to ensure that radioactive leakage from the primary containment following a DBA, or radioactive release due to a fuel handling accident, or radioactive material released in the waste gas storage area is collected and filtered for iodine removal prior to discharge to the atmosphere at the SLCRS Vent.

An important secondary function of the system is the removal of heat from areas contiguous to containment where equipment important to safety is located (i.e., the charging pump cubicles, the low head safety injection pump cubicles, the recirculation spray pump cubicles, the auxiliary feedwater pump room, the east and west cable vaults, the MCC room, and the safeguards pipe tunnel). Following a loss of offsite power, SLCRS is the only available means of assuring that components in these areas do not exceed the design temperatures. Temperature switches are provided to open SLCRS dampers when area temperatures exceed 110°F.

The supplementary leak collection and release system consists of two 100 percent capacity leak collection exhaust fans with a design capacity of 50,000 cfm each. Air is exhausted from the fuel building, waste gas storage area, blowdown tank room, personnel access hatch area, purge air duct area, east cable vault, pipe tunnel and north and west safeguards areas and, during refueling, the containment.

The capacity of each fan is in excess of the estimated air inleakage to the containment contiguous areas, fuel building and waste gas storage area. An intake damper is provided at the suction header of the fans to provide makeup air. The excess capacity of the fan ensures a minimum of the required negative pressure in the exhausted areas. Provision is made in the various exhausted areas to permit confirmation that they are maintained at the required negative pressure.

The provision made to confirm the maintenance of required negative pressure areas served by the supplementary leak collection and release system consists of the use of differential pressure gauges. These gauges are portable instruments which indicate pressure in inches water gauge either above or below the prevailing atmospheric pressure. Periodic observation of gauge pressure readings will confirm that the subject areas are maintained at the required negative pressure.

In order to limit air leakage into the above structures to the capacity of a leak collection exhaust fan, penetration pipes, ducts and cables are sealed as required at or near the point where they pass from the contiguous structure to some other structure, e.g., the auxiliary building. Inleakage of air at doors in exhausted structures is limited by gasketing. Doors are either locked or are self-closing and are under administrative control.

One of the leak collection exhaust fans is normally used to exhaust the various areas. The other fan is used as a standby.

During normal operation, the exhaust to the fan does not go through filters. On a containment isolation phase A signal or a high-high radiation signal from monitors in the ventilation exhausts from the fuel building, the waste gas storage area, or from areas contiguous to the containment with the exception of the main steam valve cubicle, the leak collection system exhaust is diverted so that it first flows through one of the two parallel main filter banks before flowing to the leak collection exhaust fans. The other main filter bank is used as a backup. Each main filter bank consists of roughing filters, charcoal filters and pleated glass fiber type HEPA filters. The roughing filters remove large particulates to prevent excessive pressure drop buildup on the charcoal and HEPA filters. The charcoal filters are effective for radioactive iodine removal, and the HEPA filters, at a rated efficiency of 99.97 percent where tested with 0.30 micron diameter of particle, remove particulates and charcoal fines. Each charcoal filter is rated at 600 cfm. Each roughing

and HEPA filter is rated at 1,200 cfm. It is of flat parallel tray design, containing approximately 44 lb of charcoal in two 2 inch beds having a total of about 8 sq ft of face area. The media is new impregnated activated coconut shell charcoal. The media particle size is from 8 to 16 U. S. Sieve mesh with not more than 5.0 percent retained on 8 mesh nor more than 5.0 percent passing through 16 mesh. Charcoal cells are leak tested in accordance with Technical Specifications.

Charcoal filter efficiency is based on the attenuation of radioactive iodine with a minimum composite efficiency of 95 percent with the influent iodine composed of 90 percent elemental and 10 percent organic iodine.

A heat detection and alarm and automatically actuated water spray deluge system is provided for the charcoal cells to maintain cooling of the media and prevent ignition in the event of decay heat buildup.

The leak collection exhaust fans discharge through a duct to the SLCRS Vent. The SLCRS Vent is located on the top of the containment structure. The containment extends 144 ft above grade. The duct and supporting structure is designed to accommodate seismic forces. The release above the containment is a high-velocity discharge at an elevation of 150 ft above grade.

During refueling, the fuel building and containment are normally maintained at negative pressures of 0.125 inches of water column, by the operating leak collection exhaust fan.

During Mode 6, SLCRS ventilation damper VS-D-4-18A is normally closed and the upstream containment contiguous areas are not ventilated.

If there should be a fuel building high-high radiation signal, the exhaust from the fuel building along with the rest of the leak collection system exhaust, is diverted to one of the main filter banks in the leak collection release system before being released at the SLCRS Vent.

6.6.3 Evaluation

The supplementary leak collection and release system incorporates redundant 100 percent capacity leak collection exhaust fans and main filter banks. In addition, there are redundant dampers where required. The redundant fans and dampers are connected to different emergency buses, which are capable of being supplied either from normal or emergency power sources. Thus, there is sufficient redundancy in the system to ensure system reliability. Proper operation of the system is further ensured by the capability for testing the system periodically.

The instrumentation, control and electrical equipment of the supplemental leak collection system are in accordance with IEEE 279[1]-1971 and IEEE 308[2]-1971 with one exception.

IEEE 279-1971 requires that the "protection system shall, with precision and reliability, automatically initiate appropriate protective action whenever a condition monitored by the system reaches the preset level". It also requires that this be accomplished with a single failure.

The exhausts from the contiguous areas, (with the exception of the main steam valve cubicle), the fuel building and the waste gas storage area are each monitored by a radiation monitor which automatically diverts the exhaust through a filter path when the radiation reaches a preset level. Should any of these systems fail, a redundant backup radiation monitor, located in the SLCRS Vent duct, would indicate and alarm to the operator that the preset level had been reached, which would alert the operator to manually divert the exhaust through the filters. The automatic and manual systems are redundant and on separate power supplies.

The radioactivity release from the contiguous and waste gas storage areas is expected to be much less than specified by the guidelines described in 10CFR100.

The supplementary leak collection and release system collects, filters and releases at an elevated point (SLCRS Vent) the leakage from the containment following a DBA and refueling accident. Essentially, all the leakage from the containment following a DBA flows into those containment contiguous areas which house the various containment penetrations and the engineered safeguards equipment circulating radioactive water.

Although a negative pressure of .125 inch water gauge in the areas contiguous to Containment is adequate to prevent exfiltration under DBA conditions, no credit has been taken for the collection of containment leakage through any electrical penetration in the LOCA analysis of Section 14.3. Such leakage is modeled as the release of .1% volume per day directly to the environment without regard to the specific location of the containment isolation failure.

The only credit taken for SLCRS is for the collection and filtration of leakage from ESF piping systems and components that recirculate containment sump water outside the containment. A negative pressure of .125 inch water gauge is required only for those areas.

The SLCRS Vent in the supplementary leak collection and release system is located above the top of the containment. The high velocity, coupled with the mass flow rate, ensures adequate stack effect for wind speeds below 2 m/second. At wind velocities considerably in excess of 2 m/second, some entrainment of the

TABLE 6.3-3

READOUTS ON THE CONTROL BOARD WHICH OPERATOR CAN MONITOR DURING INJECTION PHASE

VALVES[1]

FSAR Figure	Actuation Position on Injection	Valve No.	Description
6.3-8	Normally Closed	MOV-SI836	ALT. HI-HEAD COLD LEG ISOLATION
6.3-8	Open	MOV-SI867 A, B, C, D	B.I.T. ISOLATION VALVES
6.3-1	Normally Open	MOV-SI865 A, B, C[2][3]	S.I. ACCUM ISOLATION VALVES
6.3-8	Normally Open	MOV-SI890 C[2][3]	LOW-HEAD S.I. ISOLATION TO COLD LEGS
6.3-8	Normally Open	MOV-SI862 A, B	LOW-HEAD S.I. PUMP RWST ISOLATION
6.3-8	Normally Closed	MOV-SI860 A, B	CONTAINMENT SUMP ISOLATION VALVES
6.3-8	Normally Closed	MOV-SI863 A, B	LOW-HEAD TO HI-HEAD S.I. PUMP ISOLATION
6.3-8	Normally Open	MOV-SI864 A, B	LOW-HEAD S.I. PUMP DISCHARGE CROSS-CONNECT ISOLATION
6.3-8	Normally Open	MOV-SI885 A, B, C, D[2]	LOW-HEAD S.I. PUMP MINIFLOW ISOLATION

TABLE 6.3-3

READOUTS ON THE CONTROL BOARD WHICH OPERATOR CAN MONITOR DURING INJECTION PHASE

VALVES[1]

FSAR Figure	Actuation Position on Injection	Valve No.	Description
6.3-8	Normally Closed	MOV-SI869 A, B	HI-HEAD S.I. HOT LEG
6.3-8	Normally Closed	MOV-SI890 A, B	LOW-HEAD, HOT LEG POST ACCIDENT RECIRC. ISOLATION
6.3-8	Closed	MOV-CH289	NORMAL CHARGING ISOLATION OUTSIDE CONTAINMENT
6.3-8	Closed	MOV-CH310	NORMAL CHARGING ISOLATION INSIDE CONTAINMENT
6.3-8	Closed	MOV-LCV-CH 115 C, E	VCT TO CHARGING PUMP ISOLATION
6.3-8	Open	MOV-LCV-CH 115 B, D	RWST TO HI-HEAD S.I./ CHARGING PUMP ISOLATION

TABLE 6.3-3

READOUTS ON THE CONTROL BOARD WHICH OPERATOR CAN MONITOR DURING INJECTION PHASE

INSTRUMENTS

FSAR Figure	Instrument No.	Description
6.3-8	FI-SI946	Low Head S.I. Pump B Flow
6.3-8	FI-SI945	Low Head S.I. Pump A Flow
6.3-8	FI-SI943	Cold Leg Hi-Head Inj. Header Flow
6.3-8	FI-SI940	Hot Leg Hi-Head Recirculation Header Flow
6.3-8	FI-SI960	Loop 2 Hot Leg Hi-Head Recirculation Flow
6.3-8	FI-SI961	Loop 1 Cold Leg Hi-Head Inj. Flow
6.3-8	FI-SI962	Loop 2 Cold Leg Hi-Head Inj. Flow
6.3-8	FI-SI963	Loop 3 Cold Leg Hi-Head Inj. Flow
6.3-8	FI-SI932	Loop 3 Hot Leg Hi-Head Recirculation Flow
6.3-8	FI-SI933	Loop 1 Hot Leg Hi-Head Recirculation Flow

TABLE 6.3-3

READOUTS ON THE CONTROL BOARD WHICH OPERATOR CAN MONITOR DURING INJECTION PHASE

PUMPS

FSAR Figure	Pump
6.3-8	Low Head Safety Injection
6.3-8	Safety Injection Charging
6.4-1A	Quench Spray
6.4-1B	Recirculation Spray
6.4-1A	Chemical Injection

Notes:

(1) Individual position lights are provided to indicate the full open or full closed position of each valve.

(2) Valves actuate a combination light and alarm if not fully open.

(3) If valve position is not corrected after alarm defined by note two occurs, an hourly reflash will occur.

TABLE 6.3-9

NOMINAL (DESIGN) EXTERNAL RECIRCULATION LOOP LEAKAGE (SAFETY INJECTION SYSTEM ONLY)

	Items	No. of Units	Type of Leakage Control and Unit Leakage Rate	Leakage to Atmosphere, cc per hr	Leakage to Vent and Drain System, cc per hr
1.	Low Head Safety Injection Pumps	2	Tandem mechanical seal with demineralized water interface between seals - leakage essentially zero(1)	0	0
2.	Safety Injection Charging (High Head) Pumps	3	Mechanical seal with leakoff - (10 cc/hr/seal) 2 seals per pump	0	60
3.	Flanges:				
	a. Pumps		Gasket - adjusted to zero leakage following any test - ten drops per minute, per flange (30 cc/hr)		
	(1) LHSI	2		60	0
	(2) HHSI	15		450	0
	b. Misc. large valves > 2 inches	57	Gasket and/or packed stems (20 cc/hr)	1,140	0
	c. Misc. flanges	10	Gasket - ten drops per minute, per flange (30 cc/hr)	300	0
4.	Misc. Small Valves ≤ 2 inches	144	Gasket and/or packed stems (3 cc/hr)	432	0
			TOTALS	2,382	60

(1) Seals are acceptance tested to essentially zero leakage.

TABLE 6.4-1 (CONT'D)

QUENCH SPRAY SUBSYSTEM COMPONENT DESIGN DATA

Chemical Injection Pumps (Cont'd)

Materials(2)

Pump casing	ASME SA-351 CF8M
Shaft	ASTM A-582 - Type 416
Rotor	ASTM A-536
Idler	ASTM A-536

NOTES:

(1) Two speed pumps

(2) Materials listed in this table may be replaced with materials of equivalent design characteristics. The term "equivalent" is described in UFSAR Section 1.8.2, "Equivalent Materials."

(3) Pump 1A has a larger impeller.

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2. Pressurizer pressure and level sensors are required to operate during the first half hour following an accident, or until the pressure and water level are reduced below the span of the instruments, whichever happens first.

3. The containment sump level instrumentation will function for at least 3 hours following an accident.

4. The air and motor operated containment isolation valves (phase A and B containment isolation) will function on initiation from a safety injection signal (for phase A) or a high-high containment pressure signal (for phase B).

Beaver Valley's Environmental Qualification Program maintains ranges of environmental conditions for plant areas in which Class 1E electrical equipment components are or could be located in the future. Refer to the BVPS-1 Environmental Qualification Program for a listing of these areas.

7.1.2.4 Quality Assurance

Descriptions of applicable quality assurance can be found in Appendix A.

7.1.2.5 Safety-Related Equipment Identification

There are four separate protection sets identifiable with process equipment associated with the reactor trip and ESF actuation systems. A protection set is comprised of more than a single process equipment rack. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment rack sets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, containment penetrations and equipment racks to the redundant trains in the logic racks. At the logic racks the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains.

The color coded nameplates described below provide identification of equipment associated with protective functions and their channel set association:

Protection Set	Color Coding
I	Red with white lettering
II	White with black lettering
III	Blue with white lettering
IV	Yellow with black lettering

Each field wire termination point is tagged to assist identification. However, the tags are not color coded.

All non-rack mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure which houses them. All cables are numbered with identification tags.

For further details of the process analog system, see Sections 7.2, 7.3 and 7.7.

There are identification nameplates on the input panels of the digital logic system. For details of the digital logic system, see Sections 7.2 and 7.3.

The installation of other cable complies with the criteria presented in Section 8.

7.2.1.1.4 Reactor Coolant System Low Flow Trips

These trips protect against a DNBR of less than the design limit in the event of a loss-of-coolant flow situation. The means of sensing the loss-of-coolant flow are as follows:

Low Reactor Coolant Flow

The parameter sensed is reactor coolant flow. Three elbow taps in each coolant loop are used as a flow device that indicates the status of 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. An output signal from two-out-of-three bistables in a loop would indicate a low flow in that loop.

The coincidence logic and interlocks are given in the Technical Specifications.

The detailed functional description of the process equipment associated with the trip function is provided in Reference 1.

Reactor Coolant Pump Breaker Trip

Opening of two or three reactor coolant pump breakers (depending upon power level), which is indicative of an imminent loss-of-coolant flow in those loops, will also cause a reactor trip. No credit is taken in the accident analyses for operation of this trip.

One set of auxiliary contacts on each pump breaker serves as the input signal to the trip logic. The coincident logic and interlocks are given in the Technical Specifications.

Reactor Coolant Pump Bus Undervoltage Trip

This trip is a back-up to the low reactor coolant flow trip to protect against low flow which can result from loss of voltage to more than one reactor coolant pump (e.g., from unit blackout). No credit is taken in the accident analyses for operation of this trip.

There is one undervoltage sensing relay connected to each reactor coolant pump bus. These relays provide an output signal when the bus voltage goes below 75 percent of rated voltage. Signals from these relays are time delayed to prevent spurious trips caused by short term voltage perturbations. The coincidence logic and interlocks are given in the Technical Specifications.

Reactor Coolant Pump Bus Underfrequency Trip

This trip is a back-up to the low reactor coolant flow trip to protect against low flow resulting from bus underfrequency for example, a major power grid frequency disturbance. A reactor coolant pump trip is also initiated in order to disengage the pumps from the power grid so that pump kinetic energy is available for full coastdown. No credit is taken in the accident analyses for operation of this trip.

The function of this trip is to open the reactor coolant pump breakers and trip the reactor for an underfrequency condition. The setpoint of the underfrequency relays is 58 Hz.

There is one underfrequency sensing relay connected to each reactor coolant pump bus. Signals from relays connected to any two of the buses (time delayed up to approximately 0.2 sec to prevent spurious trips caused by short term frequency perturbations) will trip all of the reactor coolant pump breakers. The same signal will also directly trip the reactor if the power level is above P-7.

The reactor coolant pump breaker circuits are non-safety related. No credit is taken in the accident analyses for operation of the reactor trips associated with inputs from the reactor coolant pump breakers and reactor coolant pump buses.

Figure 7.2-1, Sheet 5, shows the logic for the Reactor Coolant System (RCS) low flow trips.

7.2.1.1.5 Steam Generators Trips

The specific trip functions generated are as follows:

Low Feedwater Flow Trip

This trip protects the reactor from a sudden loss of the heat sink. The trip is actuated by steam/feedwater flow mismatch (one-out-of-two) in coincidence with low water level (one-out-of-two) in any steam generator. No credit is taken in the accident analyses for operation of this trip.

Figure 7.2-1, Sheet 7, shows the logic for this trip function.

There are no interlocks associated with this trip.

A detailed functional description of the process equipment associated with this function is provided in Reference 1.

Low-Low Steam Generator Water Level Trip

This trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a low feedwater flow reactor trip. This trip is actuated on two-out-of-three low-low water level signals occurring in any steam generator.

The logic is shown on Figure 7.2-1, Sheet 7. A detailed functional description of the process equipment associated with this trip is provided in Reference 1.

7.2.1.1.6 Turbine Trip-Reactor Trip

The turbine trip-reactor trip is actuated by two-out-of-three logic from the low auto stop oil pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip

causes a direct reactor trip above P-9. No credit is taken in the accident analyses for operation of this trip.

High-high steam generator level signals in two-out-of-three channels for any steam generator will actuate a turbine trip, trip the main feedwater pumps, and close the main and bypass feedwater control valves. The purpose is to protect the turbine steam piping from excessive moisture carryover caused by high-high steam generator level. Other turbine trips are discussed in Section 10.

The logic for this trip is shown on Figure 7.2-1, Sheet 7.

The analog portion of the trip shown on Figure 7.2-1, Sheet 15, is represented by dashed (----) lines. When the turbine is tripped, turbine auto stop oil pressure drops, and the pressure is sensed by three pressure sensors. A digital output is provided from each sensor when the oil pressure drops below a preset value. These three outputs are transmitted to two redundant two-out-of-three logic matrices, either of which trips the reactor above P-9.

The auto stop oil pressure signal also dumps the auto stop emergency trip fluid closing all of the turbine steam stop valves. When all stop valves are closed, a reactor trip signal will be initiated if the reactor is above P-9. This trip signal is generated by redundant (two each) limit switches on the stop valves.

7.2.1.1.7 Safety Injection Signal Actuation Trip

A reactor trip occurs when the Emergency Core Cooling System (ECCS) is actuated. The means of actuating the ECCS are described in Section 7.3. This trip protects the core against a loss of reactor coolant or steam.

Figure 7.2-1, Sheet 8, shows the logic for this trip. A detailed functional description of the process equipment associated with this trip function is provided in Reference 1.

7.2.1.1.8 Manual Trip

The manual trip consists of two switches with multiple outputs on each switch. One output is used to actuate the train A trip breaker and another output actuates the train B trip breaker. Operating a manual trip switch removes the voltage from the undervoltage trip coil and energizes the shunt trip coil either of which will cause a reactor trip.

There are no interlocks which can block this trip. Figure 7.2-1, Sheet 3, shows the manual trip logic.

7.2.1.1.9 System Accuracies

The system accuracies of the instrument trip signals required for unit safety are given in Table 7.2-3.

7.2.1.1.10 Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC)

AMSAC provides a backup system diverse and independent from the existing Reactor Protection System to (1) initiate a turbine trip and (2) initiate Auxiliary Feedwater flow, thereby providing adequate assurance that the Reactor Coolant System will not be subject to potential damage as a result of overpressure in the event of an ATWS with coincident loss of feedwater.

AMSAC monitors feedwater flow in each of the three loops. Any two-out-of-three loops indicating a loss of feedwater flow initiates the AMSAC System timer, provided that the plant is at 40% turbine load or greater, or if the plant was at 40% turbine load or greater within the previous 180 seconds, as sensed by two-out-of-two turbine impulse pressure channels.

7.2.1.2 Reactor Trip System Interlocks

7.2.1.2.1 Power Escalation Permissives

The overpower protection provided by the out-of-core nuclear instrumentation consist of three discrete, but overlapping levels. Continuation of startup operation of power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one of two intermediate range permissive signal (P-6) is required prior to source range level trip blocking and detector high voltage cutoff. Source range level trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P-6) level. There is a manual reset switch for administratively reactivating the source range level trip and detector high voltage when between the permissive P-6 and P-10 level, if required. Source range level trip block and high voltage cutoff are always maintained when above the permissive P-10 level.

The intermediate range level trip and power-range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from two of four power range channels.

Individual blocking switches are provided so that the low-range power range trip and intermediate range trip can be independently blocked. These trips are automatically reactivated when any three of the four power range channels are below the Permissive (P-10) level, thus ensuring automatic activation to more restrictive trip protection.

The development of the permissives P-6 and P-10 is shown on Figure 7.2-1, Sheet 4. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

See Technical Specifications for the list of protection system interlocks.

7.2.1.2.2 Blocks of Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip at low power (below approximately 10 percent full power) on a low reactor coolant flow or reactor coolant pump open breaker signal in more than one loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, pressurizer high water level. See Figure 7.2-1 for permissive applications. The low power signal is derived from three-out-of-four power range neutron flux signals below the setpoint in coincidence with two-out-of-two turbine impulse chamber pressure signals below the setpoint (low unit load).

The P-8 interlock blocks a reactor trip when the unit is below 30 percent of full power, on a low reactor coolant flow in any one loop. The block action (absence of the P-8 interlock signal) occurs when three-out-of-four neutron flux range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor will be allowed to operate with one inactive loop, and trip will not occur until two loops are indicating low flow. See Figure 7.2-1, Sheet 4, for derivation of P-8, and Sheet 5 for applicable logic.

The P-9 interlock blocks a reactor trip on a turbine trip at less than or equal to 49 percent power. The block action (absence of the P-9 interlock signal) occurs when three out of four neutron flux range signals are less than or equal to the 49 percent power level set point. Thus below the P-9 set point, the reactor will be allowed to operate and ride out the turbine trip transient, with load rejection with reactor power dissipated by steam dump.

See Technical Specification for the list of Reactor Trip System Interlocks.

7.2.1.3 Coolant Temperature Sensor Arrangement

The hot and cold leg temperature signals required for input to the protection and control functions are obtained using thermowell mounted RTDs installed in each reactor coolant loop.

The hot leg temperature measurement in each loop is accomplished using three fast response narrow range RTDs mounted in thermowells. The hot leg thermowells are located within the three scoops previously used for the RTD bypass manifold. The scoops were modified during the seventh refueling outage by drilling a flow hole in the tip of the scoops so water will flow in through the existing holes in the leading edge of the scoop, pass the RTD and out through the new drilled hole in the tip of the scoop.

The cold leg temperature measurements in each loop are accomplished by one fast response narrow range duel element RTD. The existing cold leg RTD bypass penetration nozzle was modified to accept the thermowell and RTD.

Due to temperature streaming, the three fast response hot leg RTDs are electronically averaged to generate the hot leg temperature.

In the event one of the three hot leg RTDs fails, the failed RTD will be disconnected and the hot leg temperature measurement will be obtained by averaging the remaining two RTD measurements in that loop. A bias adjustment will be applied to correct for the temperature offset. The bias adjustment will be based on the most recent periodic temperature measurement obtained at full power prior to the RTD failure. Subsequent measurements obtained from the remaining RTDs in that loop and the other loop RTDs may be used to (1) confirm the correct bias adjustment or (2) define changes required to the bias adjustment. In the event a cold leg RTD fails, the failed RTD should be disconnected from the logic cabinets and the installed spare cold leg RTD would then be connected in the failed RTD's place.

Operation with less than two hot leg RTDs per loop or with both cold leg RTD elements per loop failed is not permissible. This channel is considered inoperable and should be placed in trip.

The basis for operation utilizing the thermowell mounted RTDs is presented in Reference 24.

7.2.1.4 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation includes a slight modification of the usual tank level arrangement using differential pressure between upper and a lower tap. The modification consists of the use of a sealed reference leg instead of the conventional open column of water. Refer to Section 7.2.2.3.4 for an analysis of this arrangement.

7.2.1.5 Analog System

The process analog system is described in Reference 1.

7.2.1.6 Digital Logic System

The solid state protection logic system takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of unit parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage coils of the reactor trip circuit breakers when the necessary combination of signals occur. The system also provides annunciator, status light and computer input signals which indicate the condition of bistable input signals, partial trip and full trip functions and the status of the various blocking, permissive and actuation functions. In addition, the system includes means for semi-automatic testing of the logic circuits. A detailed description of this system is given in Reference 3.

Single Failure Criterion

The protection system is designed to provide redundant (one-out-of-two, two-out-of-three or two-out-of-four) instrumentation channels for each protective function and one-out-of-two logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

Single failure within the protection system shall not prevent proper protective action at the system level when required. Components and systems not qualified for seismic events or accident environments and nonsafety-grade components and systems are assumed to fail to function if failure adversely affects protection system performance. These components and systems are assumed to function if functioning adversely affects protection system performance. All failures in the protection system that can be predicted as a result of an event for which the protection system is designed to provide a protective function are assumed to occur if the failure adversely affects the protection system performance. After assuming the failures of nonsafety-grade, non-qualified equipment and those failures caused by a specific event, a random single failure is assumed. With these failures assumed, the protection system must be capable of performing the protective functions credited in the accident analyses. This design meets the requirements of the GDC 20 and IEEE 279-1971.

Loss of input power, the most likely mode of failure, to a channel or logic train will result in a signal calling for a trip. This design also meets the requirements of the GDC 26.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation and testing as well as administrative control during design, production, installation and operation are employed, as discussed in Reference 6. This design also meets the requirements of GDC 19.

Quality of Components and Modules

For a discussion on the quality of the components and modules used in the reactor trip system, refer to Appendix A.4. The quality used also meets the requirements of GDC 1.

Equipment Qualification

Temperature in the control room and electronic equipment room is maintained for personnel comfort at 70±10°F. Design specifications for this equipment require that no loss of protective function should result when operating in temperatures up to 120°F and humidity up to 95 percent which may occur upon the loss of air conditioning and/or the ventilation system. Thus, there is a wide margin between the design limit and the normal operating environment for the protective equipment.

Loss of the control room air-conditioning units will not adversely affect the operability of safety-related control and electrical equipment. Redundant river water cooling coils are provided as a back-up, in the event of failure of the air-conditioning units. Use of the river water cooling coils limits the worst case temperature environment to 120°F (equipment design limit) and is a condition that would require reactor shutdown. Electrical control system malfunction does not occur at temperature levels below 120°F, but it is considered that operator inefficiency for prolonged periods at elevated temperatures precludes continuous plant operation. Loss of ventilation in other equipment rooms containing safety-related control and electrical equipment will not adversely affect their operability because redundant ventilation systems or redundant safety-related control and electrical equipment are provided. Ventilation systems are designed to limit temperature to 104°F in spaces housing 40°C motors and 120°F in spaces housing 50°C motors. In the unlikely event that all ventilation is lost, both normal and redundant, space temperature will rise, creating a limiting condition necessitating plant shutdown. The average ambient limiting air temperature in areas containing electrical or instrumentation control equipment that would cause the plant to be shut down is covered in the Technical Specifications.

The normal operating temperature for the protective equipment in the containment will be maintained below 120°F (except that for out of core neutron detectors the normal operating temperature will be maintained below 135°F). The protective equipment is designed for continuous operation within design tolerance in this environment.

Qualification testing has been performed on the various protective system equipment. This testing included demonstrating operation of safety functions at elevated ambient temperatures up to 120°F and relative humidity up to 95 percent for control room and electronic equipment room equipment and in the full post-accident environment for a specified time for equipment required in the containment. Detailed results of these tests are retained by the suppliers. Qualification testing of safety equipment required to operate in the post accident environment is discussed in References 12 and 20. For Stone & Webster supplied equipment, the control equipment supplier has performed factory tests, which verify that the equipment will operate at temperatures up to 120°F without malfunction.

The neutron detectors are designed for continuous operation at 135°F (the normal operating environment is below this value) and are capable of operation at 175°F for 8 hr. The power range detectors have been tested in temperatures in excess of 175°F for a period of 16 hr with negligible decrease in insulation resistance. The insulation resistance is the governing factor for severe environments. Temperature detectors are located in the neutron shield tank with indication and alarm in the control room.

The results of testing discussed in the above paragraphs demonstrates that the design meets the requirements of GDC 23.

7.2.2.2.3 Evaluation of Compliance With IEEE Std. 323-1971[16]

Safety-related equipment is type tested to substantiate the adequacy of design. This is the preferred method as indicated in Reference 16. Type tests may not conform to the format guidelines set forth in Reference 16.

7.2.2.2.4 Evaluation of Compliance With IEEE Std. 334-1971

The only continuous duty, Class I motors in containment are the inside recirculation spray pump motors. These will be specified to be tested in the manner set forth in IEEE Std. 334-1971.[17]

7.2.2.2.5 Evaluation of Compliance With IEEE Std. 338-1971[14]

The periodic testing of the reactor trip system conforms to the requirements of Reference 14 with the following comments:

1. Protection system overall response time testing is conducted in accordance with the time intervals specified in the Technical Specifications, and consists of a series of response time tests of discrete portions of the system with the results summed and verified to be within the limits of the overall system requirement. The overall response time testing is usually conducted during refueling outages and is rechecked if a component, significantly affecting the time response, is replaced during maintenance.

2. The reliability goals specified in Paragraph 4.2 of Reference 14 are being developed and adequacy of test frequencies will be demonstrated at a later date.

3. The periodic test frequency discussed in Paragraph 4.3 of Reference 14 and specified in the Technical Specifications is conservatively selected to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to unit condition changes, the test frequency is accelerated to accommodate the situation until the marginal performance is resolved.

4. The test interval discussed in Paragraph 5.2, Reference 14, is developed primarily on past experience and modified if necessary to ensure that system and subsystem protection is reliably provided.

   Analytic methods for determining reliability are not used to determine test interval.

7.2.2.2.6 Evaluation of Compliance With IEEE Std. 344-1971

The seismic testing, as discussed in Section 7.2.1.10, References 8, 9, 10 and 11, conforms to the guidelines set forth in IEEE Std. 344-1971[18] with the exceptions noted in Section 7.2.1.10.

7.2.2.2.7 Evaluation of Compliance With AEC General Design Criteria[19]

The reactor trip system meets the requirements of the GDC wherever appropriate. Specific cases are noted as they are discussed in Section 7.

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

The flux difference between the upper and lower long ion chambers from three of the four power range neutron detectors are used as inputs to the overtemperature ΔT and overpower ΔT setpoints. The isolated output from the fourth channel is used for automatic rod control.

In addition, a deviation signal will give an alarm if any neutron flux channel deviates significantly from any of the other channels. Also, the control system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear channel will block automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint. A negative reactivity insertion in excess of Technical Specifications implies a dropped rod. The reactor will be tripped to assure automatic rod withdrawal does not cause a DNBR of less than the design limit.

7.2.2.3.2 Coolant Temperature

The input signals to the Reactor Control System are obtained from electronically isolated protection Tavg and Delta-T signals, (one per loop). A Median Signal Selector (MSS) is implemented in the Reactor Control System, one for Tavg and one for Delta-T.

The MSS receives three signals as input and selects the medium signal for input to the appropriate control systems. Any single failure (high or low) in a calculated temperature will not result in adverse control system behavior since the failed high or low temperature signal will be rejected by the MSS.

Hence, the implementation of an MSS in the Reactor Control System in conjunction with the two out of three protection logic satisfies the requirements of IEEE 279-1971, Section 4.7, "Control and Protection System Interaction."

The response time allocated for measuring RCS hot and cold leg temperature using thermowell mounted fast response RTDs is as specified in the BVPS-1 License Requirements Manual.

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the median value. Automatic rod withdrawal blocks will also occur if any two of the temperature channels indicate an overtemperature or overpower condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature ΔT trip protection function. This unit uses separate channels for protection and control.

A spurious high pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip logic and in the logic for safety injection to ensure low pressure protection.

The pressurizer heaters are incapable of overpressurizing the reactor coolant system. Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2,500 psia and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power-operated relief valves during this surge.

In addition, operation of any one of the power-operated relief valves can maintain pressure below the high pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

7.2.2.3.4 Pressurizer Water Level

Three pressurizer water level channels are used for reactor trip. Isolated signals from these channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of half an hour or more).

Experience has shown that hydrogen gas can accumulate in the upper part of the condensate pot on conventional open reference leg systems in pressurizer water level service. At reactor coolant system operating pressures, high concentrations of dissolved hydrogen could blow water out of the reference leg and cause a large level error, measuring higher than actual level. Accurate calculations of this effect have been difficult to obtain. To eliminate the possibility of such effects, a bellows is used in a pot at the top of the reference leg to provide an interface seal and prevent dissolving of hydrogen gas into the reference leg water. Supplier tests were run which confirmed a time response of less than 1.0 sec.

The reference leg is uninsulated and will remain at local ambient temperature. This temperature will vary somewhat over the length of the reference leg piping under normal operating condition but will not exceed 140°F. During a blowdown accident, any reference leg water flashing to steam will be confined to the condensate steam interface in the condensate pot at the top of the temperature barrier leg and will have only a small (about 1 inch) effect on measured level. Some additional error may be expected due to effervescence of hydrogen in the temperature barrier water. However, even if complete loss of this water is assumed, the error will be less than 1 ft and can be tolerated.

Calibration of the sealed reference leg system is done in place after installation by application of known pressure to the low pressure side of the transmitter and measurement of the height of the reference column. The effects of static pressure variations are predictable. The largest effect is due to the density change in the saturated fluid in the pressurizer itself. The effect is typical of level measurements in all tanks with two phase fluid and is not peculiar to the sealed reference leg technique. In the sealed reference leg, there is a slight compression of the fill water with increasing pressure, but this is taken up by the flexible bellows. A leak of the fill water in the sealed reference leg can be detected by comparison of redundant channel readings on line and by physical inspection of the reference leg off line. Leaks of the reference leg to atmosphere will be immediately detectable by off scale indications and alarms on the control board. A closed pressurizer level instrument shutoff valve would be detected by comparing the level indications from the redundant level channels (three channels). In addition, there are alarms on one of the three channels to indicate an error between the measured pressurizer water level and the programmed pressurizer water level. There is no single

inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The channel calibration may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

3. CHANNEL FUNCTIONAL TEST: A channel functional test shall be the injection of a simulated signal into the channel as close to the primary sensor as practicable to verify operability, including alarm and/or trip functions.

   The minimum frequency for check, calibration and testing are defined in the Technical Specification. Based on experience in operation of both conventional and nuclear unit systems, when the unit is in operation, the minimum checking frequencies set forth therein are considered adequate.

7.2.3.2 Periodic Testing of the Nuclear Instrumentation System

The following periodic tests of the nuclear instrumentation system are performed:

1. Testing at unit shutdowns
   a. Source range testing
   b. Intermediate range testing
   c. Power range testing.
2. Testing between P-6 and P-10 permissive power levels:
   a. Source range testing
   b. Intermediate range testing
   c. Power range testing.
3. Testing above P-10 permissive power level:
   a. Intermediate range testing
   b. Power range testing.

Operability of the neutron flux rate trip channels associated with dropped rods and ejected rod protection is verified periodically by introduction of a step change using the channel drawer test circuits. The test method includes verification of the time delay set into the rate unit during preoperational tests. The value of the time constant is set during initial start-up test by introduction of a step change using the Nuclear Instrument channel drawer test circuits. This test will be repeated periodically as required to verify the network time constant.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and troubleshooting procedures provided in the unit technical manual for the nuclear instrumentation system. Control and protection trip settings are indicated in the Technical Specifications.

7.2.3.3 Periodic Testing of the Process Analog Channels of the Protection Circuits

The following periodic tests of the analog channels of the protection circuits are performed:

1. T_{avg} and ΔT protection channel testing
2. Pressurizer pressure protection channel testing
3. Pressurizer level protection channel testing
4. Steam/feedwater flow protection channel testing
5. Steam generator level protection channel testing
6. Reactor coolant flow protection channel testing
7. Impulse chamber pressure channel testing.

The following conditions are required for these tests:

1. These tests may be performed at any unit power from cold shutdown to full power.
2. Before starting any of these tests with the unit at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode in order to avoid spurious trips.
3. Testing is conducted in accordance with the Technical Specifications.

In addition to the above, the trips identified in Section 7.2.2.2.1 as not being testable at power will be tested periodically at shutdown.

6, 7 and 8 of Figure 7.2-1. Tables 7.3-1 and 7.3-2 give additional information pertaining to logic and function.

The interlocks associated with the ESF actuation system are outlined in Table 7.3-3. The interlocks satisfy the functional requirements discussed in Section 7.1.2.

The transfer from the safety injection mode to the recirculation mode will automatically take place on two out of four low level signals from the refueling water storage tank (RWST) coincident with a safety injection signal.

7.3.1.1.2 Devices Requiring Actuation

The following are the actions which the ESF actuation system initiates when it is called on to perform its function:

1. Safety injection
2. Reactor trip
3. Feedwater line isolation by closing all main control valves, feedwater pump trip and closure of main feedwater pump discharge valves (Feedwater System containment isolation valves are also closed by a safety injection signal or high high steam generator water level signal, however, no credit is taken for this action in the safety analyses).
4. Auxiliary feedwater system actuation
5. River water (pump start and system isolation)
6. Containment depressurization system
7. Containment isolation
8. Control room ventilation system isolation and pressurization
9. Emergency diesel startup
10. Main steam line isolation.

7.3.1.2 Design Bases: IEEE Std. 279-1971[2]

The unit conditions which require protective action are given in Section 7.3.1.1. The unit variables that are required to be monitored in order to provide protective actions are also summarized in Section 7.3.1.1.

The only variable sensed by the ESF actuation system which has spatial dependence is reactor coolant temperature. The effect on the

measurement is negated by taking multiple samples from the reactor coolant hot leg and averaging these samples electronically in the process protection system.

The parameter values that will require protective action are given in the Technical Specification.

The malfunctions, accidents or other unusual events which could physically damage protection system components or could cause environmental changes are as follows:

1. Loss of Coolant Accident (LOCA)
2. Steam breaks
3. Earthquakes
4. Fire
5. Explosion (Hydrogen buildup inside containment)
6. Missiles
7. Flood

Minimum performance requirements are as follows:

1. SYSTEM RESPONSE TIMES: Are defined as the time interval from when the monitored parameter exceeds its ESF actuation setpoint at the sensor until the ESF equipment is capable of performing its safety function (valves have repositioned, pumps have started and discharge pressures are at their required values). These times include sensor response times and diesel generator starting and sequence loading delays where applicable.

   The system response time does not specifically include any effects associated with transfer functions (dynamic compensators - lag, lead/lag and rate lags). Plant safety analyses typically use both the system response time and applicable dynamic compensators (modeled separately) to calculate the overall response of a protective function to changes in an input parameter.

   During periodic system response time testing, it is not always practical (or desirable) to turn off transfer functions. The use of a step input change allows for time response testing to be performed with dynamic compensation operational.

   For a listing of the actual overall BVPS Unit 1 ESF response time requirements, refer to the Licensing Requirements Manual (LRM).

2. SYSTEM ACCURACIES: System accuracies are as defined in UFSAR Table 7.2-3 for all identified reactor trip system and ESF parameters.

3. RANGES OF SENSED VARIABLES: Ranges of sensed variables required to generate the protection action are:

   a. For loss of coolant accident

      1) Pressurizer pressure 1,700 to 2,500 psig

      2) Containment pressure -10 to 55 psig

   b. For steam break protection

      1) Steam line pressure 0 to 1,200 psig

      2) Containment pressure -10 to 55 psig

7.3.1.3 Implementation of Functional Design

7.3.1.3.1 Analog Circuitry

The process analog sensors and racks for the ESF actuation system are covered in Reference 1. Discussed in this report are the parameters to be measured including pressures, tank and vessel water levels, and temperatures, as well as the measurement and signal transmission considerations. These latter considerations include the basic current transmission system, transmitters, orifices and flow elements, resistance temperature detectors and pneumatics. Other considerations covered are automatic calculations, signal conditioning and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in Section 4, reactor coolant system. The secondary system sensor locations are shown on the steam system flow diagrams given in Section 10.

Containment pressure is sensed by four physically separated differential pressure transmitters mounted by strong supports outside of the containment. The distance from penetration to transmitter is kept to a minimum and separation is maintained. This arrangement conforms to GDC 53.

The following is a description of those process channels not included in the reactor trip or ESF actuation systems which enable additional monitoring of in-containment conditions in the post LOCA recovery period. These channels are located outside of the containment (with the exception of sump instrumentation) and will not be affected by the accidents:

1. REFUELING WATER STORAGE TANK LEVEL: Level instrumentation on the refueling water storage tank consists of four qualified Class 1E independent channels. Three of the level channels have indication in the control room and the fourth is recorded. Two channels, one for each train, are alarmed. Four distinct level setpoints are employed for alarm and control.

   a. ABOVE NORMAL LEVEL - used to avoid overfilling of the tank.

   b. BELOW NORMAL LEVEL - alarms if the level drops below the Technical Specification required volume for injection by the emergency core cooling system in the event of a loss of coolant accident.

   c. LEVEL LOW - in addition to the indicators and recording in the control room, any one of the four level channels actuates a common alarm in the main control room. A two-out-of-four low level signal coincident with a safety injection signal automatically transfers operation from the injection phase to the recirculation phase and also provides alarm indication.

   d. COLD SHUTDOWN LEVEL LOW - alarms if the level drops below the Technical Specification required volume for an operable borated water source during cold shutdown.

2. SAFETY INJECTION CHARGING PUMPS DISCHARGE PRESSURE: These channels clearly show that the pumps are operating. The transmitters are outside the containment.

3. PUMP ENERGIZATION: Pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board.

4. VALVE POSITION: All ESF systems remote operated valves have position indication on the control board to show proper positioning of the valves. Red and green indicator lights are located next to the manual control station showing open and closed positions. In the cases of the accumulator isolation valves, redundancy of position indication is provided by valve stem mounted limit switches which actuate annunciators on the control board when the valves are not

correctly positioned for safeguards. The low head injection discharge valve to the cold legs (MOV-SI890C) uses a similar stem mounted limit switch to annunciate should the valve be out of position. However, since the valve operator has the power locked out, the normal red and green indicators lights will be off.

The stem mounted switches are independent of the motor operator limit switches and control power. See Section 7.6 for additional information.

5. SUMP INSTRUMENTATION: The containment sump instrumentation consists of three multi-level magnetic float type switches. There are two wide range (0-90 inches) transmitters and one narrow range (3-15 inches) transmitter. The narrow range transmitter monitors the sump level under normal conditions. Both wide range levels and the narrow range level are displayed in the control room. A recorder in the control room is provided for one of the wide range level signals.

   The containment sump level instrumentation was upgraded as a requirement of an NRC Order[14] in response to NUREG 0737 TMI issue II.F.1.5.

   In addition to the above instrumentation, the following local instrumentation is available:

   a. Containment depressurization spray test lines total flow.

   b. Safety injection test line pressure and flow.

7.3.1.3.2 Digital Circuitry

The ESF actuation logic racks are discussed in detail in Reference 3. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 3 also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, consideration for accomplishing physical separation and provisions for ensuring instrument qualification. The outputs from the analog channels are combined into actuation logic as shown on sheets 5 (T_{avg}), 6 (pressurizer pressure), 7 (steam pressure) and 8 (ESF actuation) of Figure 7.2-1.

To facilitate ESF actuation testing, two cabinets (one per train) are provided which enable operation, to the maximum practical extent, of safety features loads on a group by group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.2.

7.3.1.3.3 Final Actuation Circuitry

The outputs of the solid state logic protection system (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are listed as follows:

1. Safety injection system pump and valve actuators. See Section 6 for flow diagrams and additional information.

2. Containment isolation (Phase A - signal isolates all non-essential process lines on receipt of safety injection signal: Phase B - signal isolates remaining process lines (which do not include safety injection lines) on receipt of two-out-of-four high-high containment pressure signal). For further information see Section 6.

3. River water pump and valve actuators (Section 9)

4. Auxiliary feed pumps start (Section 10)

5. Diesel start (Section 8)

6. Feedwater isolation (Section 10)

7. Control room and supplementary leak collection ventilation valves and damper actuators and control room pressurization valves (Section 6 and 9)

8. Steam line isolation valve actuators (Section 10)

9. Recirculation spray and quench pumps and valve actuators (Section 6).

If an accident is assumed to occur coincident with a static electrical blackout, the ESF loads must be sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in Section 8. The design conforms to 1967 GDC 37 and 41.

7.3.1.4 Auxiliary Systems Required for ESF Operation

The following auxiliary systems are essential to the proper functioning of engineered safety features:

1. River water system (continuously after Design Base Accident (DBA).

2. Emergency diesel generator fuel oil system (continuously after DBA)

3. Control room air-conditioning system (continuously after DBA)

4. Control room air pressurization system (60 min after DBA)

5. Leak collection system (continuously after DBA)

6. Diesel generator building ventilation system (continuously after DBA)

7. Intake structure ventilation system (continuously after DBA)

8. Emergency switchgear and battery room ventilation system (continuously after DBA)

9. Electrical power distribution system (continuously after DBA)

Instrumentation and controls required for the above auxiliary systems are designed to the same standards as those for the ESF Systems that they support, including IEEE Std. 279-1971.[2] The 2 train design concept featuring independence and separation between trains, is utilized for all instrumentations and controls that are necessary for the ESF auxiliary systems to perform their safety functions. Included are all components from the sensors to the actuated equipment of the systems.

A separate power supply will be provided for each train. A loss of electric power to one train will not affect the operation of the redundant train. Each train will be supplied from a separate emergency bus.

Indication of interrelated system variables will provide the operator with sufficient information to determine the response of the ESF systems if one of the auxiliary system monitors should fail. For example, if the flow measurement loop in the river water line going to a recirculation spray cooler fails, the temperature indicator of the cooled fluid will indicate whether the cooler is functioning properly.

Special consideration is given to the environmental and seismic capabilities of instrumentation and control equipment in the ESF auxiliary systems. Verification that the equipment has been designed, built and installed in accordance with the specified criteria is accomplished through analysis, performance test and/or type test data and quality assurance and quality control methods. Testing and inspection of instrumentation associated with ESF auxiliary systems is performed on the instrumentation associated with the parts of the system that will not be in use during normal unit operation. Instrumentation associated with ESF auxiliary systems that will be in use during normal operation (river water system) will not require periodic testing, since operability will be demonstrated by their continuous use. The following discusses the instrumentation and controls for the auxiliary systems required to support the ESF:

River Water System

The river water system is described in Section 9.9 and is shown on Figure 9.9-1. The river water system is required to supply cooling water for ESF and auxiliary systems essential to ESF:

1. Four recirculation spray heat exchangers

2. Three high-head safety injection pump lube oil coolers

3. Two emergency diesel generator cooling system heat exchangers.

4. The control room air-conditioning condensers.

Three river water pumps are provided to supply water to the two river water headers. Connection of pumps and valves for the system are described in Section 9.9.2.

Continuous radiation monitoring will be provided in the river water discharge from the component cooling water heat exchangers during normal operation (Section 11.3.3.3.17). After an accident that activates the containment isolation phase B signal, continuous radiation monitoring will be provided in the discharge of each train of recirculation spray heat exchangers (Section 11.3.3.3.18). Each recirculation spray heat exchanger will have a remotely operated valve in its supply and discharge line. On a high radiation alarm, the operator can isolate the affected recirculation spray heat exchanger train by closing the isolation valves and its supply and return header.

Control switches and indicating lights for the river water pump motors will be provided on the main control board. Any river water pump can be started manually from the control room. A standby river water pump will be started automatically when either a diesel loading sequence signal is received or on receipt of safety injection signal with normal power available. All other pressure in either of the two river water headers will be visually and audibly alarmed in the control room.

Redundant supply headers, each having redundant actuated supply valves, supply water to the recirculation spray heat exchangers. Each diesel generator heat exchanger is supplied by a single supply header with redundant actuated supply valves.

Emergency Diesel Generator Fuel Oil System

The emergency diesel generator fuel oil system design and description is given in Section 9.1 and shown in Figure 9.14-1. This system is required to supply fuel oil to the emergency diesel generator day tanks for proper operation of the emergency diesel generators. The emergency generator fuel oil system is divided into two separate redundant mechanical and electrical trains. This dual train concept provides sufficient redundancy that will prevent failure of an active or passive component from impairing the system's capability to supply fuel oil to at least one of the diesel engines.

Each of the two emergency diesel generator fuel oil storage tanks is provided with fuel oil tank level indication locally. Each of the two emergency diesel generator oil day tanks is provided with level switches, which will automatically start and stop the associated fuel oil transfer pumps. In addition to the level switch for pump control, local manual control of the pump is provided.

At a predetermined high or low level, separate emergency diesel generator day tank level switches will actuate a high or low alarm on the emergency diesel generator panel. Controls and indication will be tested functionally during startup and periodically thereafter as stated in Section 9.14.6.

Ventilation Systems

The objective of the instrumentation and controls for the safety-related ventilation system components is to maintain temperature within the designed limits required.

Manual controls and indication of the status of all safety-related components are available in the main control room. Automatic and manual controls of redundant components are independent and are electrically and physically separated. Failure of an operating component and/or starting of the redundant component is indicated in the control room. Redundant motors and motor-operated dampers have power supplied from separate emergency buses. Motor-operated dampers fail in the as-is position on loss of power. Each redundant air-operated damper and damper seal with solenoid pilot valve has power supply to the solenoid from a separate d-c bus. The air-operated dampers are designed to fail in the position of greater safety on the loss of air and/or power.

Electrical Power Distribution System

The electrical power distribution system and its design bases are described in Section 8.

7.3.2 Analysis

7.3.2.1 Evaluation of Compliance With IEEE Std. 279-1971[2]

7.3.2.1.1 Single Failure Criteria

The discussion presented in Section 7.2.2.2.1 is applicable to the ESF actuation system, with the following exception.

In the ESF, a loss of instrument power will call for actuation of ESF equipment controlled by the specific bistable that lost power (containment depressurization spray excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in Section 8. For containment depressurization spray, the final bistables are energized to trip to

avoid spurious actuation. In addition, manual containment depressurization spray requires simultaneous actuation of both manual controls. This is considered acceptable because spray actuation on high-high containment pressure signal provides automatic initiation of the system via protection channels meeting the criteria in Reference 2. Moreover, all safety related equipment (valves, pumps, etc.) can be individually manually actuated from the control board. Hence, a secondary mode of containment depressurization spray initiation is available. This design conforms to 1967 GDC 21 and 26.

7.3.2.1.2 Equipment Qualification

The environmental qualification of safety related electrical equipment, required to perform a safety function under postulated accident conditions, was reviewed. A summary of the BVPS-1 safety related electrical equipment identified was included in the responses to NRC IE Bulletin 79-01B[9] and to 10 CFR 50.49[11,12]. This information is maintained in the BVPS-1 Environmental Qualification Program in accordance with 10 CFR 50.49.

The environmental qualification program addresses aging, submergence, loss of coolant accident and main steam line break inside primary containment, and various high energy line breaks outside primary containment.

The resistance temperature detectors for T_{avg} measurement are only required as a backup to the steamline pressure instruments during the accidents; however, they are qualified to operate in the accident environment. They are typically rugged devices and are expected to survive in the environment long enough to perform their initiation function (less than 1 min), and are not subsequently used.

The steam line flow sensors are also required only for steam break accidents and are expected to perform their initiation function within a relatively short period of time (less than 1 min) following the break. However, they are qualified to operate in the accident environment.

7.3.2.1.3 Channel Independence

The discussion presented in Section 7.2.2.2.1 is applicable. The ESF outputs from the solid state logic protection cabinets are redundant and the actuations associated with each train are energized up to and including the final actuators by the separate a-c power suppliers which power the logic trains.

7.3.2.1.4 Control and Protection System Interaction

The discussions presented in Section 7.2.2.2.1 are applicable.

7.3.2.1.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.2.2.1 are applicable to the sensors, analog circuitry and logic trains of the ESF actuation system.

The following discussions cover those areas in which the testing provisions differ from those for the reactor trip system:

Testing of ESF Actuation Systems

The ESF systems are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program, which conforms to GDC 25, 38, 46, 48, 57, and to the Safety Guide 22, is performed in accordance with the requirements specified in the Technical Specifications.

During on-line operation of the reactor, all of the ESF analog and logic circuitry will be fully tested. In addition, essentially all of the ESF final actuators will be fully tested. The remaining few final actuators whose operation is not compatible with continued on-line unit operation will be partially tested with the exception of the automatic transfer from safety injection to recirculation feature that is tested during plant shutdown.

During normal operation, the operability of testable final actuation devices of the ESF will be tested by manual initiation from the safeguards test panel.

Under the present design, those protection functions which are only partially tested at power are the following:

1. Closing the main steam valves (see discussion under Section 7.3.2.1.5, Actuation testing).
2. Closing the feedwater control valves.
3. Closing the feedwater pump discharge valves.
4. Tripping the main feedwater pump circuit breakers.
5. Closing the reactor coolant pump seal water return isolation valves.
6. Closing the reactor coolant pump component cooling water isolation valves.
7. Turbine trip.

The actuation logic for the functions listed is tested as described in this section. As required by Safety Guide 22, where actuated equipment is not tested during reactor operation, it has been determined that:

1. There is no practicable system design that would permit operation of the actuated equipment without adversely affecting the safety or operability of the plant.

2. The probability that the protection system will fail to initiate the operation of the actuated equipment is, and can be maintained, acceptably low without testing the actuated equipment during reactor operation.

3. The actuated equipment can routinely be tested when the reactor is shut down.

Where the ability of one of the two trains to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main control room by a common "ESF testing" annunciator for the train in test. Test circuitry does not permit the two ESF trains to be tested at the same time so that extension of the bypass condition to the redundant train is prevented.

In accordance with an NRC Order[13], administrative procedures are implemented to require redundant independent verification of the operability of the remaining engineered safety features whenever any safety system, or subpart thereof, is intentionally removed from service.

Performance Test Acceptability Standard for the Safety Injection Signal and for the Containment Isolation Phase B (CIB) Signal Generation

During reactor operation, the basis for ESF actuation systems acceptability will be the successful completion of the overlapping tests performed on the reactor trip and the ESF actuation systems. Analog checks verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of these circuits through to and including the logic input relays. Solid state logic testing checks and digital signal path from and including logic input relay contacts through the logic matrices and master relays and perform continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing a unit transient. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication and visual observation that the appropriate pump breakers close and automatic valves shall have completed their travel.

The basis for acceptability for the ESF interlocks will be control board indication of proper receipt of the signal upon introducing the required input at the appropriate setpoint.

Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments, are based on qualifications test data which identifies what constitutes acceptable radiation, thermal, etc., degradation.

Frequency of Performance of ESF Actuation Tests

Complete system testing is performed in accordance with the frequency specified in the Technical Specifications.

ESF Actuation Test Description

The following sections describe the testing circuitry and procedures for the on-line portion of the testing program. The guidelines used in developing the circuitry and procedures are:

1. The test procedures must not involve the potential for damage to any unit equipment.

2. The test procedures must minimize the potential for accidental tripping.

3. The provisions for on-line testing must minimize complication of ESF actuation circuits so that their reliability is not degraded.

Description of Initiation Circuitry

Several systems comprise the total ESF system, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in Section 7.3.1.1.5) are initiated by a common signal (safety injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, component cooling and river water, is initiated via the safeguards starting sequence actuated by the safety injection signal.

Each function is actuated by a logic circuit which is duplicated for each of the two redundant trains of ESF initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The logic, master and slave relays are mounted in the solid state logic protection cabinets designated train A and train B, respectively, for the redundant counterparts. The master and slave relays circuits operate various pump and fan circuit breakers or starters, motor-operated valve contactors, solenoid operated valves, emergency generator starting, etc.

Analog Testing

Analog testing is identical to that used for reactor trip circuitry and is described in Section 7.2.3.3. Briefly, in the analog racks, bistable trip switches, proving lamps and analog test switches are provided. Administrative control requires, during bistable testing, that the bistable output be put in a trip condition by its trip switch which connects the proving lamp to the bistable and disconnects and thus de-energizes (operates) the bistable output relays in train A and train B cabinets. This, of necessity, is done on one channel at a time. Status lights and single channel trip alarms in the main control room verify that the bistable relays have been de-energized and the bistable outputs are in the trip mode. An exception to this is containment depressurization spray and RWST level, which are energized to actuate two-out-of-four and reverts to two-out-of-three when one channel is in test.

The analog test switch is then operated and a signal is inserted through a test jack. Verification of the bistable trip setting is now confirmed by the proving lamp.

Solid State Logic Testing

After the individual channel analog testing is complete, the logic matrices are tested from the train A and train B logic rack test panels. This step provides overlap between the analog and logic portions of the test program. During this test, each of the logic inputs are actuated automatically in all combinations of trip and non-trip logic. Trip logic is not maintained sufficiently long enough to permit master relay actuation; master relays are "pulsed" in order to check continuity. Following the logic testing, the individual master relays are actuated electrically to test their mechanical operation. Actuation of the master relays during this test will apply to low voltage to the slave relay coil circuits to allow continuity checking, but not slave relay actuation. During logic testing of one train, the other train can initiate the required ESF function. For additional details, see Reference 3.

Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished.

In the next step, operation of the slave relays and the devices controlled by their contacts will be checked. For this procedure, control switches mounted on a safeguards test cabinet panel in the logic rack area are provided for each slave relay. These controls are of the type that require two deliberate actions on the part of the operator to actuate a slave relay. By operation of these relays one at a time through the control switches, all devices that can be operated on line are tested.

The procedures require testing at various locations.

1. Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of bistable relay operation is done at the main control room status lights.

2. Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

3. Testing of pumps, fans and valves is done at a test panel located in the vicinity of the logic racks in combination with the control room operator.

4. Continuity testing for those circuits that cannot be operated is done at the same test panel mentioned in 3 above.

Testing During Shutdown

Emergency core cooling system (ECCS) tests will be performed at each major fuel reloading. With RCS pressure less than or equal to 350 psig and temperature less than or equal to 350 F, a test safety injection signal will be applied to initiate operation of the system.

Containment depressurization spray system tests are discussed in Section 6.4 and the Technical Specifications.

Periodic Maintenance Inspections

The maintenance procedures which follow may be accomplished in any order. The frequency will depend on the operating conditions and requirements of the reactor power unit. If any degradation of equipment operation is noted, either mechanically or electrically, remedial action is taken to repair, replace or readjust the equipment. Optimum operating performance must be achieved at all times.

Typical maintenance procedures include the following:

1. Check cleanliness of all exterior and interior surfaces

2. Check all fuses for corrosion

3. Inspect for loose or broken control knobs and burned out indicator lamps

4. Inspect for rust, moisture and condition of cables and wiring

5. Check all connectors and terminal boards for looseness, poor connection or corrosion

6. Inspect components for signs of overheating or component deterioration

7. Perform complete system operating check.

The balance of the requirements listed in Reference 2 (Paragraphs 4.11 through 4.22) are discussed in Section 7.2.2.2.1. Paragraph 4.20 of Reference 2 receives special attention in Section 7.5.

7.3.2.2 Evaluation of Compliance With IEEE Std. 308-1969[5]

See Section 8, which discusses the power supply for the protection systems, for discussions on compliance with this criteria.

7.3.2.3 Evaluation of Compliance With IEEE Std. 323-1971[6]

The safety-related equipment is type tested to substantiate the adequacy of design. This is the preferred method as indicated in Reference 6. Type tests may not conform to the format guidelines set forth in Reference 6.

7.3.2.4 Evaluation of Compliance With IEEE Std. 338-1971[7]

The periodic testing of the Westinghouse ESF actuation system conforms to the requirements of Reference 7 with the following comments:

1. Protection system overall response time testing is conducted in accordance with the time intervals specified in the Technical Specifications, and consists of a series of response time tests of discrete portions of the system with the results summed and verified to be within the limits of the overall system requirement. The overall response time testing is usually conducted during refueling outages and would be required to be checked if a component, significantly affecting the time response, had been replaced during maintenance.

2. The reliability goals specified in Paragraph 4.2 of Reference 7 are being developed and adequacy of test frequencies will be demonstrated at a later date.

3. The periodic test frequency discussed in Paragraph 4.3 of Reference 7 and specified in the unit Technical Specification is conservatively selected to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to unit condition changes, the test frequency is accelerated to accommodate the situation until the marginal performance is resolved.

In addition to actuation of the ESF, the effect of a steam break accident also generates a signal resulting in a reactor trip on overpower or following ECCS actuation. However, the core reactivity is further reduced by the highly borated water injected by the ECCS.

The analyses in Section 14 of the steam break accidents and an evaluation of the protection system instrumentation and channel design shows the ESF actuation systems are effective in preventing or mitigating the effects of a steam break accident.

References for Section 7.3

1. J. A. Nay, "Process Instrumentation for Westinghouse Nuclear Supply Systems", WCAP-7671, Westinghouse Electric Corporation (April 1971).

2. "Criteria for Protection Systems for Nuclear Power Generating Stations", IEEE Std. 279-1971, The Institute of Electrical and Electronics Engineers, Inc.

3. D. N. Katz, "Solid State Logic Protection System Description" WCAP-7672, Westinghouse Electric Corporation (June 1971).

4. Deleted by Rev. 0.

5. "Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations", IEEE Std. 308-1969, The Institute of Electrical and Electronic Engineers, Inc.

6. "IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electrical Equipment for Nuclear Power Generating Stations", IEEE Std. 323-1971, The Institute of Electrical and Electronic Engineers, Inc.

7. "IEEE Trial Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protective Systems", IEEE Std. 338-1971, The Institute of Electrical and Electronic Engineers, Inc.

8. "IEEE Trial Use Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations", IEEE Std. 344-1971, The Institute of Electrical and Electronic Engineers, Inc. (August 11, 1971).

9. J. J. Carey, "Environmental Qualification of Class IE Equipment", Letter to NRC, Duquesne Light Company (October 15, 1981).

10. "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems", RG-1.47, AEC Regulatory Guide.

11. Duquesne Light Company "Response to the NRC Equipment Qualification Rulemaking (10CFR50.49)" (May 20, 1983).

12. Duquesne Light Company submittal to the NRC on Environmental Qualification of Safety-Related Electrical Equipment (November 29, 1984).

13. V. J. Stello, Jr. (USNRC), BVPS-1 Order Modifying License, letter to S. Schaffer, President, Duquesne Light Company (December 5, 1979).

14. S. A. Varga (USNRC) BVPS-1 Order Modifying License, letter to J. J. Carey (BVPS) (July 10, 1981).

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

7.5.1 Description

Tables 7.5-1 and 7.5-2 list the information readouts provided to the operator to enable him to perform required manual safety functions and to determine the effect of manual actions taken, following a reactor trip. The tables list the information readouts required to maintain the unit in a hot shutdown condition or to proceed to cold shutdown within the limits of the Technical Specifications. Reactivity control after condition II and III faults will be maintained by administrative sampling of the reactor coolant for boron to ensure that the concentration is sufficient to maintain the reactor subcritical. The SPDS was added per NRC Order[1] to address NUREG 0737 Item I.D.2.

The major station monitoring systems at the Beaver Valley Power Station are the:

1. Annunciators
2. Status Lights
3. Miscellaneous Recorders and Indicators
4. Computer Data Acquisition and Display Systems

Display units for each of the monitoring systems noted above are located in the main control room.

Information on safety-related equipment is provided to the operator by the Sequence of Events Recorder, the Plant Computer System, and the Safety Parameter Display System.

All abnormal functions related to plant safety or operation, primary and secondary plant, including critical electrical protection trips, will be monitored through the sequence of events recorder.

In general, most inputs to the sequence of events recorder are duplicated on the control room annunciators, although in many cases where practical, inputs of a similar nature connected to the sequence of events recorder on an individual basis may be grouped into one input on an annunciator. Annunciators may also have inputs that are not necessarily critical and that will not be duplicated on the events recorder.

The plant computer system is for process monitoring only. It does not control any process and it will not alarm unless some process is acting abnormally. The computer is not considered an events recorder. It provides plant data by data recording devices in the control room.

Miscellaneous recorders and indicators are provided to permit startup of the plant in the event that the plant computer is out of service.

The Safety Parameter Display System (SPDS) is a computer system installed to provide the plant operator with current plant status in iconic form. The SPDS computer system monitors many of the same analog and digital variables as recorded by the plant computer. However, whereas the purpose of the plant computer is to continually record the values of the plant variables for historical logging and display, the purpose of the SPDS computer system is to make the plant operator immediately aware of plant safety-related systems which are deviating from normal. Upon detection of an abnormal plant status, the SPDS computer system is capable of providing plant information in a form which allows the operator to analyze and diagnose the course of the abnormality, determine corrective action, and monitor plant response.

The annunciator system consists of a large number of window displays segregated into groups generally according to process or function. One group of display windows will have a first out feature, i.e., if a number of alarms on this group are annunciated almost simultaneously a means is provided to indicate which alarm occurred first.

The status of all safety-related instrument bistables is monitored by status lights, annunciators and the plant computer. All containment isolation trip valves and safety-related motor-operated valves have their status monitored by lights on the main control board. All safety related switchgear is monitored by indicating lights on the main control board.

The control, indicating, alarm and computer inputs derived from the reactor protection system circuits are electrically isolated from the latter by means of isolation amplifiers or equivalent buffering circuits. The isolation amplifiers are contained in the reactor protection circuits. As such, a failure of the output of an isolation amplifier will have no effect on the input circuit.

2. Power for the display instruments is obtained from the nominal 120 V a-c vital bus system. This system is described in Section 8.

   Those channels determined to provide useful information in charting the course of events are recorded.

References for Section 7.5

1. Darrell G. Eisenhut (USNRC) - NUREG 0737 Item I.D.2, USNRC Order to J. J. Carey (BVPS) (June 12, 1984).

2. Generic Letter 82-33, 'Supplement 1 to NUREG 0737 - Requirements for Emergency Response Capability' (December 17, 1982).

3. J. J. Carey (BVPS) "Generic Letter 82-33 Supplement 1 to NUREG 0737 Response," to Darrel Eisenhut (USNRC) (April 15, 1983).

7.6 ALL OTHER SYSTEMS REQUIRED FOR SAFETY

7.6.1 Residual Heat Removal Isolation Valves

The RHR system inlet and discharge isolation valves are normally closed and are only opened for residual heat removal after system pressure is reduced to approximately 400 psig, and system temperature has been reduced to approximately 350 F. Refer to Section 9.3 for details of the RHR system and to Section 9.3.3.2 in particular for the details on the inlet and discharge isolation valve interlocks.

7.6.2 Reactor Coolant System Loop Isolation Valve Interlocks

7.6.2.1 Description

The purpose of these interlocks is to ensure that an accidental startup of an unborated and/or cold, isolated reactor coolant loop results only in a relatively slow reactivity insertion rate.

The interlocks are required to perform a protective function. Therefore, there are two (2) independent limit switches (one on the stem and one in the motor operator) having contacts that are closed when a valve is fully open, and two (2) independent limit switches having contacts that are closed when a valve is fully closed. Other sets of the limit switch contacts operate the position indicator lights.

Another interlock includes two (2) differential pressure switches in each line which bypasses a cold leg loop isolation valve. This is the line which contains the relief line isolation valve.

It should be noted that flow through the relief line isolation valve indicates:

1. The valves in the line are open
2. The line is not blocked
3. The pump is running.

7.6.2.2 Analysis

For the analysis of this system, see Section 14.

Only those interlocks and alarms relating to core protection are described. Those required for coolant pump protection are not part of the protection system.

In addition to the interlocks, an alarm is provided to indicate that the bypass valve is not closed. This will give an alarm when all loops are required to be in service and the bypass valve is not fully closed. An alarm is used because, if the bypass

valve is opened at full power, the core flow reduction is of the order of 2 to 5 percent and does not result in an immediate DNB problem.

7.6.3 Emergency Safety Features Protection Channels Power Supply

The 120 v a-c vital bus system, which supplies engineered safety features protection channels, is discussed in Section 8.5.4 and is shown in Figure 8.4-1.

Power to rod drive mechanisms is supplied by two motor generator sets operating from two separate 480 v, three-phase buses. Each generator is the synchronous type and is driven by a 150 hp induction motor. The a-c power is distributed to the rod control power cabinets through the two series connected reactor trip breakers.

The variable speed full length rod control system rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed. A summary of the RCCA sequencing characteristics is given below.

1. Two groups within the same bank are stepped such that the relative position of the groups will not differ by more than one step.

2. The control banks are programmed such that withdrawal of the banks is sequenced in the following order: control bank A, control bank B, control bank C and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank withdrawn (bank D) is the first control bank inserted.

3. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power. The control bank insertion sequence is the opposite.

4. Overlap between successive control banks is adjustable between 0 to 50 percent (0 and 115 steps), with an accuracy of ±1 step.

5. Rod speeds for control banks are capable of being controlled between a minimum of 6 steps per min and a maximum of 72 steps per min.

7.7.1.3 Unit Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by the Nuclear Instrumentation

The nuclear instrumentation system is described in Reference 2.

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure reactor power level, axial power imbalance and radial power imbalance. These channels are capable of recording overpower excursions up to 200 percent of full power. Suitable alarms are derived from these signals as will be described below.

Basic power range signals are:

1. Total current from a power range detector (four such signals from separate detectors); these detectors are vertical and have an active length of 10 ft

2. Current from the upper half of each power range detector (four such signals)

3. Current from the lower half of each power range detector (four such signals).

Derived from these basic signals are the following (including standard signal processing for calibration):

4. Indicated nuclear flux (four such signals)

5. Indicated axial flux imbalance, derived from upper half flux minus lower half flux (four such signals).

Alarm functions derived are as follows:

6. Deviation (maximum minus minimum of four) in indicated nuclear power

7. Upper radial tilt (maximum to average of four) on upper-half currents

8. Lower radial tilt (maximum to average of four) on lower-half currents.

Provision is made to continuously record, on strip charts on the control board, the 8 ion chamber signals, i.e., upper and lower currents for each detector. Nuclear power and axial unbalance is selectable for recording as well. Indicators are provided on the control board for nuclear power and for axial power imbalance.

7.7.1.3.2 Rod Position Monitoring of Full Length Rods

The Rod Position Monitoring of Full Length Rods is described in References 4, 7 and 8. Two separate systems are provided to sense and display control rod position as described below:

1. ANALOG SYSTEM: An analog signal is produced for each RCCA by a linear variable transformer.

Direct continuous readout of every RCCA position is presented to the operator by individual meter indications, without need for operator selection or switching to determine rod position. A rod bottom (rod drop) alarm is provided.

2. DEMAND POSITION SYSTEM: The demand position system counts pulses generated in the rod drive control system to provide a digital readout of the demanded bank position.

The demand position and analog rod position indication systems are separate systems; each serves as backup for the other. Operating procedures require the reactor operator to compare the demand and analog (actual) readings upon recognition of any apparent malfunction. Therefore, a single failure in rod position indication does not in itself lead the operator to take erroneous action in the operation of the reactor.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the RCS loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip and provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection and limits rod insertion such that acceptable nuclear peaking factors are maintained. 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 raised (the rods must be withdrawn further) with increasing power. Two parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power.

The rod insertion limit monitor is a feature that alerts the operator to a reduced shutdown reactivity situation. Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail in the functional diagrams shown in Figure 7.2-1, sheet 9. In addition to the rod insertion monitor for the control banks, an alarm system is provided to warn the operator if any shutdown RCCA leaves the fully withdrawn position.

Rod insertion limits are determined by:

1. Determining the allowed rod reactivity insertion at full power consistent with the purposes given above

2. Determining the differential reactivity worth of the control rods when moved in normal sequence

3. Determining the change in reactivity with power level by relating power level to rod position

4. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarm

The demanded and measured rod position signals are displayed on the control board. They are also monitored by the unit computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system.

7.7.1.3.5 Rod Bottom Alarm

A rod bottom signal for the full length rods detector interface board in the analog/digital rod position system as described in References 7 and 8, is used to operate a control relay, which generates the "ROD BOTTOM ROD DROP" alarm.

7.7.1.4 Unit Control System Interlocks

The listing of the unit control system interlocks, along with the description of their derivations and functions, is presented in Table 7.7-2. It is noted that the designation numbers for these interlocks are preceded by "C". The development of these logic functions is shown in the functional diagrams (Figure 7.2-1, sheets 9 to 16).

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

Rod stops are the C1, C2, C3, C4 and C5 control interlocks identified in Table 7.7-2. The C3 rod stop derived from overtemperature ΔT and the C4 rod stop, derived from overpower ΔT are also used for turbine runback, which is discussed below.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two out of three coincidence logic is used.

A rod stop and turbine runback are initiated when:

$$\Delta T > \Delta T_{rod\ stop}$$

for both the overtemperature and the overpower condition.

For either condition in general:

$$\Delta T_{rod\ stop} = \Delta T\ setpoint - B_p$$

where B_p is a setpoint bias and where $\Delta T_{setpoint}$ refers to the overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the two conditions.

The turbine runback is continued until ΔT is equal to or less than $\Delta T_{rod\ stop}$

This function serves to maintain an essentially constant margin to trip.

7.7.1.5 Pressurizer Pressure Control

The RCS pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on when the pressurizer pressure controlled signal demands approximately 100 percent proportional heater power.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

value corresponding to a 10 percent step load decrease or a sustained ramp load decrease of 5 percent/minute.

Prior to engaging the turbine, heat is generally removed from the Reactor Coolant System by dumping steam to the condenser. Since T_{ref} is not available until the turbine has been placed in service, the steam dump control system is typically run in steam pressure control mode with a constant setpoint corresponding to no-load conditions. This causes T_{avg} at low power conditions to be slightly higher than program T_{avg}. This condition has been reviewed[9] and shown to be acceptable.

A block diagram of the steam dump control system is shown on Figure 7.7-7.

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensated median T_{avg} and the reference T_{avg} is based on turbine impulse chamber pressure.

The T_{avg} signal is the same as that used in the RCS. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the unit thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available in this situation, steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Reactor Trip Steam Dump Controller

Following a reactor trip, determined by the presence of the reactor trip breaker open signal, the load rejection steam dump controller is defeated and the reactor trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead/lag compensated median T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined setpoint the first two banks of steam dumps actuate open in a prescribed sequence. As the error signal reduces in magnitude indicating that the reactor coolant system T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the reactor trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

The error signal determines whether a group of valves is to be tripped open or modulated open. In either case, they are modulated when the error is below the trip-open setpoints.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine/reactor trip on load rejection.

7.7.1.9 Incore Instrumentation

The incore instrumentation system consists of Chromel-Alumel thermocouples at fixed core outlet positions and 50 flux thimbles for movable miniature neutron detectors which can be positioned at the center of selected fuel assemblies, anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown in Figure 7.7-8. Sections 1 and 2 of Reference 5 outline the incore instrumentation system in more detail. The minimum number of operable incore thermocouples for plant operation is defined by Technical Specifications.

7.7.1.9.1 Thermocouples

Chromel-Alumel thermocouples are inserted into tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals, a conoseal and swage type seal from conduit to head. The thermocouples are supported in guide tubes in the upper core support assembly. The incore thermocouples are monitored by the Train A and B Inadequate Core Cooling (ICC) Monitoring System as described in Section 7.8.4 and can be read on the ICCM graphic displays in the Control Room. Isolated outputs of the ICC monitors provide incore thermocouple signals to the plant computer and the Safety Parameter Display System Computer. The incore thermocouples have been environmentally qualified for use in post accident monitoring in accordance with NUREG-0737.

7.7.1.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. See Reference 5 for neutron flux detector parameters. The stainless steel detector shell is welded to the leading end of carbon-steel helical wrap drive cable and to stainless steel or Inconel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of drive assemblies, five path rotary transfer

transient because of coolant contraction. The pressurizer low pressure trip setpoint is programmed so that the pressure following the turbine and reactor trip is above the low pressurizer pressure safety injection setpoint. If heaters become uncovered following the trip, they are de-energized and the CVCS will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The steam dump feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no load temperature following the trip to ensure adequate reactivity shutdown margin.

References for Section 7.7

1. Deleted by Revision 0.

2. J. B. Lipchak and R. A. Stokes, "Nuclear Instrumentation System," WCAP-7669, Westinghouse Electric Corporation (April 1971).

3. A. E. Blanchard and D. N. Katz, "Solid State Rod Control System, Full Length," WCAP-7778, Westinghouse Electric Corporation (December 1971).

4. A. E. Blanchard, "Rod Position Monitoring," WCAP-7571, Westinghouse Electric Corporation (March 1971).

5. J. J. Loving, "In-Core Instrumentation (Flux-Mapping System and Thermocouples)," WCAP-7607, Westinghouse Electric Corporation (July 1971).

6. "Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Std. 279-1971, The Institute of Electrical and Electronic Engineers, Inc.

7. "Interface Requirements for the Beaver Valley Unit 1 CERPI System," 00197-ICE-4101, ABB Combustion Engineering Nuclear Operations.

8. "Technical Description for the Beaver Valley Unit 1 CERPI System," 00197-ICE-4403, ABB Combustion Engineering Nuclear Operations.

9. E. A. Dzenis, "Responses to T_{avg} Variation Questions," Westinghouse Electric Corporation letter, DLC-99-744 (June 17, 1999).

TABLE 7.1-3

(DELETED)

TABLE 7.7-1

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT UNIT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated Accuracy	Indicator/ Recorder	Location	Notes
NUCLEAR INSTRUMENTATION						
1. Source Range						
a. Count rate	2	1 to 10^6 counts/sec	±7% of the linear full scale analog voltage	Both channels indicated. Either may be selected for recording.	Control board	
b. Startup rate	2	-1.5 to 5.0 decades/min	±7% of the linear full scale analog voltage	Both channels indicated.	Control board	
2. Intermediate Range						
a. Flux level	2	8 decades of neutron flux corresponds to 0 to full scale analog voltage overlapping the source range by 2 decades	±7% of the linear full scale analog voltage and ±3% of the linear full scale voltage in the range of 10^{-4} 10^{-3} amps	Both channels indicated. Either may be selected for recording.	Control board	One two-pen recorder is used to record any of the 8 nuclear channels (2 source range 2 intermediate range and 4 power range)

TABLE 7.7-1 (CONT'D)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT UNIT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated Accuracy	Indicator/ Recorder	Location	Notes
NUCLEAR INSTRUMENTATION (CONT'D)						
b. Startup rate	2	-1.5 to 5.0 decades/min	±7% of the linear full scale analog voltage	Both channels indicated	Control board	
3. Power Range						
a. Uncompensated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 120% of full power	±1% of full span	All 8 current signals indicated	NIS Racks in control room	
b. Compensated ion chamber current (top and bottom) uncompensated ion chambers)	4	0-120% of full power	±2% of full power	All 8 current signals recorded (four 2-pen recorders). Recorder 1 - upper current for two diagonally opposed detectors.	Control board	

SECTION 8

ELECTRICAL SYSTEMS

LIST OF EFFECTIVE PAGES

Page Numbers	Revision in Effect	Date
8i and 8ii	Revision 18	January, 2000
8-1 and 8-2	Revision 17	January, 1999
8-3	Revision 12	January, 1994
8.1-1	Revision 18	January, 2000
8.1-2 and 8.1-3	Revision 0	January, 1982
8.2-1	Revision 18	January, 2000
8.2-2	Revision 0	January, 1982
8.3-1	Revision 18	January, 2000
8.3-2	Revision 14	January, 1996
8.3-3 and 8.3-4	Revision 13	January, 1995
8.4-1 through 8.4-3	Revision 17	January, 1999
8.4-4	Revision 18	January, 2000
8.4-5	Revision 17	January, 1999
8.4-6 and 8.4-7	Revision 18	January, 2000
8.4-8 and 8.4-9	Revision 17	January, 1999
8.5-1 and 8.5-2	Revision 18	January, 2000
8.5-3	Revision 12	January, 1994
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8.5-7	Revision 12	January, 1994
8.5-8 through 8.5-10	Revision 18	January, 2000
8.5-11	Revision 17	January, 1999
8.5-12	Revision 12	January, 1994
8.5-13 and 8.5-14	Revision 17	January, 1999
8.5-15	Revision 14	January, 1996
8.5-16	Revision 18	January, 2000
8.5-17	Revision 17	January, 1999
8.5-18 through 8.5-20	Revision 12	January, 1994
8.5-21	Revision 17	January, 1999
8.5-22 and 8.5-23	Revision 12	January, 1994
8.5-24	Revision 16	January, 1998
8.5-25	Revision 12	January, 1994
8.5-26	Revision 14	January, 1996
8.5-27	Revision 10	January, 1992
8.6-1 and 8.6-2	Revision 0	January, 1982
8.6-3	Revision 17	January, 1999
8.6-4	Revision 5	January, 1987
8.6-5	Revision 17	January, 1999

LIST OF EFFECTIVE PAGES (CONT'D)

Page Numbers		Revision in Effect	Date
Table 8.4-1	(1 of 2)	Revision 0	January, 1982
Table 8.4-1	(2 of 2)	Revision 0	January, 1982
Table 8.4-2	(Deleted)	Revision 17	January, 1999
Table 8.4-3	(Deleted)	Revision 10	January, 1992
Table 8.5-1	(Deleted)	Revision 12	January, 1994
Table 8.5-2	(Deleted)	Revision 11	January, 1993
Table 8.5-3	(1 of 1)	Revision 7	January, 1989
Table 8.5-4	(1 of 1)	Revision 10	January, 1992
Table 8.6-1	(1 of 1)	Revision 13	January, 1995
Figure 8.1-1	(Sheet 1)	Revision 18	January, 2000
Figure 8.1-1	(Sheet 2)	Revision 18	January, 2000
Figure 8.3-1		Revision 18	January, 2000
Figure 8.3-2		Revision 15	January, 1997
Figure 8.3-3		Revision 13	January, 1995
Figure 8.3-4		Revision 2	January, 1984
Figure 8.4-1		Revision 18	January, 2000
Figure 8.4-2		Revision 18	January, 2000
Figure 8.5-1		Revision 12	January, 1994
Figure 8.5-2		Revision 16	January, 1998
Figure 8.5-3	(Deleted)	Revision 12	January, 1994
Figure 8.5-4	(Deleted)	Revision 12	January, 1994
Figure 8.5-5	(Deleted)	Revision 12	January, 1994
Figure 8.5-6	(Deleted)	Revision 12	January, 1994
Figure 8.5-7		Revision 0	January, 1982
Figure 8.5-8		Revision 0	January, 1982
Figure 8.5-9	(Deleted)	Revision 10	January, 1992
Figure 8.5-10	(Deleted)	Revision 10	January, 1992
Figure 8.5-11	(Deleted)	Revision 10	January, 1992
Figure 8.5-12	(Deleted)	Revision 10	January, 1992

SECTION 8

ELECTRICAL SYSTEMS

8.1 GENERAL DESCRIPTION AND SUMMARY

The electrical systems include the equipment and systems necessary to generate power and deliver it to the high voltage switchyard. They also include facilities for providing power to and controlling the operation of electrically driven auxiliary unit equipment and instrumentation during a normal plant operation and during loss of normal station power. The main electrical connections are shown in Figure 8.1-1.

The output of the main generator is fed into and operated as an integral part of the transmission system. BVPS-1 station service power is supplied from either the main generator, the 138 kv switchyard, or a combination of both. On failure of the preferred source, automatic throwover capability is provided to the alternate source to ensure continuous power to the equipment. Section 8.4 describes the station service system. Section 8.3 describes the electrical system utility grid interconnection shown in Figures 8.3-1 and 8.3-2.

The onsite power system, which consists of the onsite a-c power system, 125 v d-c power system, and 120 v a-c vital bus system, provides power to vital station auxiliaries if a normal source of power is not available.

Two fast starting diesel generator sets provide the source of a-c power for the a-c onsite power system. A complete description of the onsite power system is found in Section 8.5.

All safety related instrumentation is fed from reliable and stable separate vital buses as described in Section 8.5.4 to guarantee continuous monitoring and control of all instrument channels. Each bus receives power from a separate battery.

Four separate unit 125 v d-c batteries with associated chargers are provided for circuit breaker control power, emergency lighting, and operating power for vital equipment until power is restored or onsite emergency power is available. A fifth 125 v d-c battery with charger is also provided for miscellaneous services not related to engineered safety features. Figure 8.4-1 illustrates the 120 v a-c vital bus and 125 v d-c systems.

Redundant circuits for essential systems are run by alternate routes which are physically separated or isolated by barriers to reduce the probability of simultaneous damage.

Safety related a-c and d-c loads are identified on Figures 8.1-1 and 8.4-2, respectively.

The electrical power systems are designed in accordance with General Design Criteria 17 and 18, Safety Guides 6 and 9, and IEEE Std. 308-1971[1] as more fully described in Section 8.2 through 8.6.

8.2 DESIGN BASES

The electrical systems are designed to ensure a continuous supply of electrical power to all essential unit equipment during normal operation and under accident conditions.

Alternate power systems, each with adequate independence, redundancy, capacity, and testability, are provided to ensure a capability for performing the function required of engineered safety features.

Onsite and offsite power systems each independently provide the total power requirements for essential systems, assuming a failure of a single active component in each system.

All components or portions of the onsite electrical system associated with the power supplied to essential systems such as motors, switchgear, batteries and chargers, etc. are capable of withstanding the maximum forces predicted at the location as a result of extraordinary natural phenomena, including earthquake, tornado, flood, high wind, or icing.

The ability of all Category I electrical equipment, which is part of the onsite power system, to perform its intended function during or following a maximum hypothetical earthquake, must be documented by test or analysis.

The seismic design criteria and method of seismic analysis and seismic testing of Category I electrical equipment is described in Appendix B.

The seismic design criteria and method of seismic analysis and seismic testing of Category I reactor protection system equipment is covered in Section 7.2.1.

The electrical systems meet the requirements of General Design Criteria 17 and 18, Safety Guides 6 and 9 and IEEE Std. 308-1971.[1] The main control room is designed in accordance with General Design Criteria 19. The offsite power system is not designed to withstand a tornado, exceptionally severe hurricanes or ice storms. However, the indoor circuit breakers and control circuits required to ensure isolation of the essential circuits and onsite power systems from the offsite power system are located in a protected area designed to withstand tornadoes, hurricanes or ice storms.

Electrical equipment for essential systems located within the containment structure is designed to operate under the conditions of temperature, pressure, and humidity which occur during and after a loss-of-coolant accident as described in Section 7.

References for Section 8.2

1. "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations", IEEE Std. 308-1971, The Institute of Electrical and Electronic Engineers, Inc.

8.3 SYSTEM INTERCONNECTIONS

Generator 1, described in Section 10.3.3, is connected through the generator lead bus to a step-up transformer, rated at 945 mva. This transformer steps the generator voltage up to 345 kv to feed two separately protected buses of the 345 kv switchyard (Figure 8.3-1). Each bus of the 345 kv switchyard is connected through 345-138 kv autotransformers to separate buses in the 138 kv switchyard.

BVPS-1 generator 1 and six transmission lines connect to the 345 kv switchyard and seven transmission lines connect to the 138 kv switchyard. Two BVPS-1 station service lines also connect to the 138 kv switchyard. Figure 8.3-1 is a one-line diagram showing the 345 kv and 138 kv switchyards and their connections to the station.

The combined 138 kv and 345 kv switchyards form a major bulk transmission switching point for the transmission system. In addition to lines connecting with other switchyards in the transmission system, there are direct ties with two large neighboring power systems.

Lines converge on the switchyards by means of two or more widely separated routes. Separation of connections to the switchyard buses varies from a center-to-center spacing of more than 400 ft between the most widely separated lines to a minimum of 45 ft for lines which terminate in adjacent bays.

Routing of rights of way, location, height, and distance between towers for lines emanating from the switchyard to the grid is provided in Figure 8.3-3.

Routing of lines from the switchyard to the plant, including an extension for BVPS-2, are shown on Figure 8.3-4. The two 138 kv lines from the switchyard to the plant are each on separate towers and have sufficient separation so that falling of one tower on the adjacent redundant circuit is not a credible accident.

A diagram of the bulk power supply transmission system for BVPS-1 and BVPS-2 in the vicinity of the Beaver Valley Power Station is shown in Figure 8.3-2.

Both switchyards have a double bus arrangement. Buses are rigid-type to provide maximum reliability. The switchyards are designed to withstand the maximum expected wind and ice loading conditions. Each bus, transformer and transmission line connected to the buses is individually protected by two independent protective relay schemes. Transmission line and transformer breakers have separately protected d-c control circuits. Each 345 kv and 138 kv circuit breaker in the switchyard is serviced by two separate 125 v d-c batteries, each feeding two separate d-c distribution panels. The 138 kv and 345 kv circuit breakers have two independent trip coils apiece, each served by separate batteries. Therefore, with a single failure of battery supply, one source is still available to

trip the breaker. Single failures of either equipment or control and protective circuits do not cause loss of power at both buses in the 345 kv or the 138 kv switchyard. Reliable offsite power is available to supply BVPS-1 station service and essential systems since offsite power is supplied by two BVPS-1 station service transformers, one from each bus of the 138 kv switchyard. The 138 kv connections between the switchyard buses and the station service transformers are made with overhead lines having separate towers for each line.

Loss of either bus 1 or bus 2 of the 138 kv switchyard reduces station service power for BVPS-1 available from the switchyard to approximately half of full-load requirements. Even without BVPS-1 station service power from the main generator and with either 138 kv bus 1 or 2 out of service, sufficient power capacity remains to provide for an orderly shutdown, and to supply all engineered safety features loads.

The capacity of each of the 138 kv buses 1 and 2 and the 138 kv lines feeding the system station service transformers for both BVPS-1 and BVPS-2, is adequate to meet the power requirements for an accident in one unit and a safe shutdown in the other unit.

Even with the loss of all except one source of power from the system to the switchyard, sufficient power capacity required for essential systems is available.

In the unlikely event that a tornado, flying missile, hurricane, or severe icing would simultaneously take out all incoming transmission lines or both 138 kv switchyard buses, the unit is designed to continue in operation, supplying station service power from the main generator. In the unlikely event of simultaneous loss of offsite power and unit generator power, the buses supplying the essential systems are automatically transferred to onsite emergency power. All indoor equipment and circuits required to ensure isolation of the onsite emergency power systems from the offsite power systems are protected by enclosures designed to withstand damage from tornadoes or flying missiles.

8.3.1 Grid Stability Study

The power network to which the Beaver Valley Power Stations are connected has been analyzed for transient stability using computer simulation.

A trip of the BVPS-1 from internal troubles in the Nuclear Steam Supply System and not related to electrical faults has very little effect on the power network. The voltage angle at the BVPS-1 shifts in position approximately 15 degrees due to inertial responses of the vast power network to supply the loss of the BVPS-1. Restoration to normal would be accomplished on a dispatch basis as required by normal control or nearby generation and switching of shunt capacitors connected to the power network. The electrical systems are stable.

Four vital instrument buses, as shown in Figure 8.4-1, are provided for all instrumentation and reactor protection circuits. Each instrument bus is fed from a station inverter. The buses are maintained at 124 ± 2.48 v and 60 ± 0.3 Hz. These vital buses are normally free from a-c station service transients or voltage variations. Section 8.5.4 described the 120 v a-c vital bus system.

The unit batteries are sized to operate turbine-generator emergency shutdown oil pumps, instrumentation, inplant communications, and vital nuclear channels for two hours without benefit of any unit power. After two hours, it is assumed that power will be restored or will be supplied from the onsite emergency power generation equipment. Section 8.5.3 describes the 125 v d-c power system.

Lighting distribution and intensities are provided in accordance with the latest recommendations of the Illuminating Engineering Society (IES). Section 8.4.4 describes the lighting system.

All electrical equipment and cables are designed to operate within their rating or temperature rise. The service factor or overload rating is not infringed on during any mode of operation for which the equipment or cabling was designed including a design basis accident.

8.4.1 Essential Emergency Systems

The two 138-4.36 kv system station service transformers, which are supplied from separate 138 kv buses in the switchyard, provide redundant sources of offsite power for the emergency systems as well as for normal service systems. Two independent sections of emergency bus, as shown in Figure 8.1-1, are supplied by isolated circuits from two normal service buses. Two breakers in series are provided in each circuit to ensure isolation from the normal service system when emergency power is being supplied by the onsite emergency diesel generators.

All equipment and circuits which normally supply offsite power to emergency systems are designed to supply the emergency loads and all connected normal loads simultaneously.

Class 1E electrical equipment is protected from sustained undervoltage conditions of 90 percent or less of motor nameplate voltage while the 4,160 v emergency buses are supplied by offsite power. The emergency bus undervoltage relays are actually set above 90 percent to account for undervoltage relay inaccuracy and voltage drop of the motor leads.

Faults on circuits supplying nonessential loads are isolated within a few cycles to ensure continuous power to essential systems.

Redundant power circuits for emergency systems are run by alternate physically separated routes or isolated by barrier walls to reduce the probability of simultaneous damage.

8.4.2 4,160 V System

The 4,160 v station service system distributes and controls power for the 4,160 v unit station service demands. The source of power is from the main generator through the BVPS-1 station service transformers 1C and 1D, system station service transformers 1A and 1B or a combination of both, as shown in Figure 8.1-1.

A load list for the 4,160 v buses is shown in Table 8.4-1. The maximum overall non-safety related loads and normal running Engineered Safety Features (ESF) loads are calculated at 14,917 kva as shown in Table 8.4-1.

All station service transformers have two secondary windings, each feeding separate buses. Each secondary winding is rated to carry 16 mva at 55°C rise with capability to supply 112 percent of this rating or 17.92 mva at a 65°C rise continuously without any change in life expectancy of insulation.

Computer studies were performed which indicate the station service transformers, under loaded conditions, are capable of providing a transfer of the 4 kv buses power supply from a preferred source to an alternate source.

The normal 4,160 v switchgear is metal-clad, with stored energy type air circuit breakers and 125 v d-c control, and is arranged in four independent bus sections. Each section is normally supplied from a separate winding of either a BVPS-1 station service transformer or a system station service transformer.

Loss of supply to any bus section automatically trips the source breaker and closes the breaker to the alternate system source providing no overload or fault exists on the bus section. A provision is also made for manual transfer, as required. All equipment and circuits are rated to start in any sequence, and to supply the entire unit service load, including emergency loads, from either source without overload.

In general, motors 250 hp and larger are operated at 4,160 v and are arranged for across-the-line starting.

One circuit from each 4,160 v bus section feeds two 4,160 v/480 v unit substation transformers, each of which is on a separate bus. Additionally, one circuit from both the 4,160 v bus 1A and 1C sections feeds a separate 4,160 v/480 v substation transformer, each of which is on a separate bus. These substation transformers supply the 480 v system described in Section 8.4.3.

Two independent sections of emergency 4,160 v bus and switchgear are provided. Each section is sized to carry 100 percent of the emergency load. Each emergency bus section is supplied from normal 4,160 v station service switchgear. Each normal switchgear bus is supplied from the selected source (station service transformers or system station service transformers) with provisions for automatic transfer to the alternate source should the preferred source fail. In the unlikely event of total loss-of-station service power, the emergency 4,160 v buses are isolated from the normal supply and energized from the emergency diesel generators, as described in Section 8.5.

Additional second level undervoltage relays, two on each 4,160 v class 1E bus and two on the secondary side of one of the two, parallel 4,160/480 v substation transformers were installed for degraded grid voltage protection. The relays have a drop out setting above 90 percent of nominal bus voltage and a maximum of 95 second time delay. The relay setting allows for relay setpoint inaccuracy and voltage drop of the motor leads to ensure that 90 percent of motor nameplate voltage is available at the motor terminals. These relays on each of the two voltage levels (4160 v and 480 v) are arranged in a two-out-of-two logic scheme. A similar protective scheme is provided on the redundant train. The primary undervoltage loss of voltage relay's setpoint is greater than or equal to 75 percent of nominal bus voltage. Refer to Technical Specifications for trip setpoint and associated time delay limits. Additional circuitry blocks the undervoltage trip load shedding on the 4160 v class 1E buses when the diesel generators are supplying these buses, and automatically reinstates load shedding when the diesel generator breakers are tripped.

8.4.3 480 v System

The 480 v station service system distributes and controls power for all 480 v and 120 v a-c unit station service demands. In general, motors rated from 60 hp to 200 hp are controlled directly by breakers in the 480 v switchgear. The source of power for the 480 v system buses is from 4,160 v station service buses. This system is shown in Figure 8.1-1.

The normal 480 v switchgear is metal-clad, with 125 v d-c operated air circuit breakers. The substations 480V bus tie breaker is closed by procedure while trying to determine the location of bus grounds and to allow maintenance on either set of bus feeder equipment. While the busses are tied together no single failure can cause the loss of both supply sources which ultimately could tie back to the physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system. Each bus section is supplied by a close coupled 4,160 v/480 v air-cooled transformer. Each bus section, with the exception of the 480 v emergency buses, is provided with automatic throwover to an alternate power source on failure of the supplying source. Two additional bus sections, with transformers, supply the screenwell and cooling tower loads.

The 480 v motor control centers are metal-clad, with combination line starters or breakers arranged in individual metal barrier compartments bolted together to form a complete motor control center. Each motor control center is supplied from a breaker in one of the 480 v switchgear buses.

Two independent sections of emergency 480 v bus and switchgear are provided. Each section is sized to carry 100 percent of the emergency load. Each emergency 480 v bus section is supplied by a close coupled 4,160 v/480 v dry type transformer which, in turn, is supplied from a breaker in one of the emergency 4,160 v bus sections.

Emergency 480 v motor control centers are provided. Each emergency 480 v motor control center is supplied by a breaker in one of the emergency 480 v switchgear buses.

Each emergency motor control center which feeds a redundant engineered safety features load is supplied with power from a separate 480 v emergency unit substation such that the loss of power on one motor control center will not affect both redundant loads.

All engineered safety items operated at 480 v a-c are fed from either the emergency 480 v switchgear or the emergency 480 v motor control center. In the unlikely event of a total loss-of-station service power, the emergency 480 v switchgear and emergency 480 v motor control centers will be supplied with power from the emergency diesel generator through the emergency 4,160 v a-c buses.

8.4.4 Lighting System

Normal lighting for the unit is supplied from the 480 v service system through single phase, 480-120/240 v, dry-type transformers.

Emergency lighting for all except control room and remote areas consists entirely of 125 v d-c incandescent units supplied from the unit battery. These units are normally energized from 120 v a-c and are automatically energized from 125 v d-c on loss of normal a-c voltage. Emergency lighting for remote areas such as the intake structure and the cooling tower area is provided by local self-contained battery-powered emergency lighting units.

Emergency lighting for the control room and main control board consists of a combination of 125 d-c incandescent units supplied from the station battery and 120 v a-c fluorescent fixtures. These a-c fixtures are fed from 480-120/240 v a-c dry-type transformers connected to the 480 v emergency buses and are continuously energized. The 125 v d-c incandescent units are energized automatically on loss of normal a-c voltage.

Additional 8-hour battery powered emergency lighting has been installed to meet 10 CFR 50 Appendix R requirements. Refer to Beaver Valley's Updated Fire Protection Appendix R Review Report, Section 10.2, for additional details.

8.4.5 Emergency Response Facility Power System

A Quality Assurance Category II diesel-backed substation provides power to the Emergency Response Facility (ERF) and selected equipment in BVPS-1 and BVPS-2 complexes as shown in Figure 8.1-1 Sheet 2 of 2.

The Emergency Response Facility Substation (ERFS) receives normal power from two 32 MVA, 138 kv - 4.36 kv/4.36 kv transformers. A 5 kv nonsegregated phase cable bus system with supports connects each transformer to the 4160 V switchgear assembly (4 KVS-BUS 1G and 1H) located in the ERFS building. Either transformer is capable of supplying both buses simultaneously via a bus tie breaker electrically connecting the two buses.

Each of the 4160 v switchgear supplies the ERF and four 480 v substations. The four substations are located in the Unit 1 turbine building, the Unit 2 Auxiliary Building, the South Office Shops Building, and in the ERFS building. The switchgear also supplies the Unit 1 dedicated auxiliary feedwater pump and the Unit 2 steam generator startup feed pump.

The 480 v substations supply five motor control centers (three for Unit 1 and two for Unit 2); Uninterruptible Power Supplies (UPS) No. 1 and No. 2; two Unit 2 Station Air Compressors; and the alternate supply to the 300 kva switchyard backup transformer.

The ERFS building receives standby power from a 2500 kw (at 104°F) ERFS diesel generator (RG-EG-1). The diesel generator supplies highly reliable power to the ERFS 4,160 v switchgear for selected equipment in the ERFS, ERF, BVPS-1, and BVPS-2. Refer to Figure 8.1-1, Sheet 2 for the loads supplied during ERFS diesel operation.

The ERFS diesel generator is housed in a prefabricated enclosure adjacent to and north of the ERFS building. A battery and a battery charger for diesel generator starting is installed in the ERFS building.

A 30,000 gallon (approx. 29,100 gallons available as configured) fuel oil storage tank is buried northwest of the switchyard relay house to provide the diesel with a 7-day fuel oil supply. Two 100 percent capacity fuel oil transfer pumps are installed on top of the fuel oil storage tank to transfer fuel oil to the diesel engine fuel oil day tank located in the southeast corner of the ERFS diesel building. Fuel oil is supplied from the day tank to the diesel fuel injectors by an engine mounted fuel pump and a fuel priming pump.

A 60-cell, 125 v d-c control storage battery supplies 125 v d-c electrical power, via battery breaker to two d-c panels for distribution to the ERFS and ERFS diesel building d-c loads.

The ERFS electrical system is controlled and monitored in the ERFS building at the ERFS diesel generator and Air-Circuit Breaker (ACB) control panels. A programmable controller provides automatic load shedding, limiting the diesel generator load to an acceptable level based on generator loading.

A redundant programmable controller system in the ERFS building provides for preprogrammed control of 4 KVS Bus 1G and 1H bus transfer, 480 VUS-Bus 1S and 1T bus transfer, alarming for blown potential transformer (PT) fuses, and for starting and automatic loading of the diesel generator.

A communication system is installed to provide communication between the ERFS building, ERFS diesel building and the BVPS-1 control room.

An automatic fire detection and protection system is provided for the ERFS building first and second floors and the ERFS diesel building. The fire detection system provides early warning of a fire in either of the two buildings to personnel in the immediate vicinity and to the control room. The fire detection system for the ERFS building consists of 32 ionization smoke detectors and for the ERFS diesel building, four ultraviolet smoke detectors. The fire detection system automatically actuates the CO_2 fire protection system for the affected areas. The CO_2 storage tank is located outside the ERFS building.

A heating, ventilating, and air conditioning (HVAC) system is provided for the ERFS building with the air conditioning servicing only the first floor. Heating and ventilating is also provided for the ERFS diesel building.

A ductline manhole system is installed from ERFS to BVPS-1 warehouse extension building, BVPS-2 condensate polishing building, System Station Service Transformers 1A and 1B and switchyard precast concrete cable trench system, and to the ERF. This is used to run the interconnecting service cables between the various stations.

Refer to Figure 1.2-1 for the location of the ERFS Building and the ERF Diesel Generator Building.

8.5 EMERGENCY POWER SYSTEM

8.5.1 General

The emergency power system is an independent, automatic starting power source which supplies power to vital station auxiliaries if a normal power source is not available.

The emergency power system, including the alternating current, direct current, and vital bus systems, is designed in accordance with IEEE Std. 308-1971[2] and is in accordance with AEC Safety Guide 6 and 1971 General Design Criteria (GDC) 17 and 18 and the intent of Safety Guide 9.

While in a test condition, several design limitations prevent the associated EDG from being capable of supplying emergency power within the required time in response to an emergency (SI/LOOP) start signal. Therefore, an EDG is inoperable while in a test condition.

An electrical calculation program is in place to monitor emergency bus load additions and deletions and to update the emergency bus loading calculations. This program ensures the capacity of emergency diesel generators continues to be adequate to power prescribed loads.

Emergency power system equipment capacities and arrangements are indicated throughout Section 8.5.

The BVPS Quality Assurance Program covers the emergency power system equipment. A description of this program is found in Appendix A.

All Category I electrical equipment was designed to withstand a design basis earthquake as described in Appendix B.

The independence between redundant emergency power sources and between their distribution systems is briefly discussed in Safety Guide 6 under Section 1.3.3.6 and is shown in Figure 8.5-1 and 8.5-2. These are summarized below:

1. The electrical power loads for engineered safety features are separated into redundant load groups fed from separate buses such that loss of one group will not prevent operation of minimum safety functions.

2. The redundant power loads are each connected to buses which may have power fed from an offsite power source or an emergency power source (usually a diesel generator).

3. Four 125 v d-c systems, each complete with batteries, chargers, switchgear, and distribution equipment are provided for engineered safety features equipment. These systems are not tied together.

4. A standby source of power for one redundant load cannot be automatically paralleled with the standby source of power for the other redundant load.

5. Each redundant a-c engineered safety feature load is supplied with power from a separate emergency diesel generator.

The physical arrangement of major pieces of emergency power system equipment is shown in Figures 1.2-1, 8.5-1, and 8.5-2.

The criteria and bases for the installation of electrical cables are given in Beaver Valley (BVPS-1) Specification BVS-3001, "Criteria for Installation and Identification of Electrical Cables". This document controls the design and installation of all cable and raceway systems. Field quality control inspections ensure compliance with this document.

All cables pertaining to reactor protection and engineered safety features equipment are installed so that redundant circuits are separated and readily identified. The redundant safety-related cables are always routed in separate raceways. In addition, the redundant cables are electrically isolated and physically separated. Physical separation is achieved by following different routes on opposite sides of masonry walls where provided. Where cables must be routed in the same area, separation is obtained by using:

1. Separate exposed or concealed metal conduit. Exposed conduit carrying nuclear instrumentation system cable for neutron detection generally have redundant channels separated by a minimum of two feet where running parallel to each other except where they are converging to termination points.

2. Separate concrete encased plastic or fiber ducts in the same bank.

3. Separate adjacent cable trays with a minimum horizontal separation of three inches between side rails and with solid metal covers.

4. Separate cable trays with a minimum vertical separation of eight inches center to center and with solid metal covers on all trays, except for a top tray which is directly under a poured concrete floor.

5. Separate exposed redundant cables with the use of protective wrap.

Exposed or concealed metallic conduit and concrete encased ducts are considered solid enclosed raceways and qualify as barriers, the minimum separation of which is one inch.

Physical separation of redundant cables in the containment penetration area is obtained by using two groups of electrical penetrations separated by a concrete wall. In the cable tunnel, a wall is provided for separation of redundant cables and cable trays are provided with solid covers.

Cables to equipment in the control room are routed through floor sleeves and floor openings from the cable spreading area below. Redundant circuits are kept separate by routing through separate sleeves or using barriers or separate conduits.

Safety related trays running in missile producing areas are installed so as to minimize or eliminate the possibility of damage from potential missiles.

Separation between redundant safeguards wiring and components in control boards, panels, and relay racks, other than those in the supply of the nuclear steam system supplier, is by means of a fire retardant barrier or a maintained air space of one inch minimum as defined in BVS-3001.

To ensure that redundant instrument channels associated with the solid state protection systems are isolated from each other and this separation is easily identified, a color coding system has been used. Channels I, II, III, and IV are color coded red, white, blue, and yellow, respectively. This channel identity need only be maintained until some channel terminating device is used. This device may be an isolating transformer or an electromagnetic relay. These channel codings are generally applied to inputs from primary and secondary process systems which are ultimately fed to the solid state protection systems. Redundant sources of power for primary process and engineered safety features, protective equipment and associated controls are identified as A and B with orange and purple color coding. Where circuits may be supplied from either A or B source, they are designated by C and color coded green.

In most cases redundant power, control, and instrumentation cables are grouped, separated and identified with a permanent type tag attached to each end of each cable. To assist further in the identification, all safety-related cables will have the appropriate color markings at intervals along its length. In no case is a safety related cable of one color code placed in the same conduit or cable tray with a cable of a different color. A non-safety related cable may run in a raceway with a safety related cable, but once associated with one train or channel, it cannot run in a raceway assigned to another train or channel.

Raceway color identification is also indicated at the end of the raceway limits, where raceway passes through a wall or sleeve, and at intervals of 50 ft maximum. The color identification consists of colored triangular decals. Each raceway also has a decal with its identification number on it. These numbers contain a color code.

When two spare source range detectors were added, portions of NIS raceways inside containment that contain cable for the detectors were not relabeled in accordance with the above described identification scheme. However, cables associated with each of the spare source range detectors were relabeled and are contained in separate conduits which extend from the keyway area to the containment penetration. The conduits, however, have only been relabeled at both ends and where easily accessible. Since NIS circuits must be in separate raceways from other circuits to avoid undesirable noise, no problems are anticipated in determining spare source range channel identity. In the keyway area, the exposed cables of redundant channels are 90° to 180° apart around the neutron shield tank.

The numbering system for cables and raceways for BVPS-1 commence with the numeral "1". For BVPS-2, the numbers commence with the numeral "2". Equipment numbers for BVPS-2 contain a distinguishable numeral "2", whereas, BVPS-1 equipment does not.

Power cables are sized in accordance with "Power Cable Ampacities," published by the Insulated Power Cable Engineers Association (IPCEA)or manufacturer's data. Sizes are based on 100 percent load factor, 90°C conductor temperature, and at the worst ambient temperature in which the cable is installed. Ampacities of power cable in tray are derated for cable installation one layer deep and six cables across with maintained horizontal spacing. Those cables which are run within the containment are qualified to perform their intended function under the worst possible environmental conditions. All cable in trays is flame retardant and has passed flame tests.

Power cable run in tray is installed in one layer with an average centerline to centerline spacing of not less than 1.25 times cable diameter. When it is impractical to maintain specified horizontal spacing, cables are further derated in accordance with IPCEA.

Power cables run in trays without maintained spacing and in random layers are derated to 40 percent of their ampacity.

All cables in trays are installed according to their level of service.

During the construction stage, the following criteria was applied to electrical cabling:

> All cables, with the exception of 500 MCM conductors, triaxial, and coaxial cables associated with neutron detectors and radiation monitoring, are terminated at terminal blocks located on either side of the containment wall at terminal cabinets. Continuity from one terminal cabinet to the other is obtained by passing the cable through the containment wall by means of electrical penetrations, which contain double pressure barrier seals and which are tested in accordance with IEEE Std. 317-1972.[3]

Triaxial and coaxial cables are terminated at the containment electrical penetrations by means of connectors, which are tested.

The 5 kv Kerite power cables and large 480 v feeders are spliced at the containment electrical penetrations. The splices are made at the cable vault area outside containment and also just inside the containment at the penetrations. The 5 kv Kerite power cables are spliced with kits ordered directly from the supplier of the cable and have been tested to be compatible with environmental conditions associated with their location. The 600 v Okonite power cables are spliced using materials furnished by the supplier of the 600 v cable and which are compatible with environmental conditions associated with their location.

The cable splicing was performed in accordance with written instructions and all safety related terminations were inspected. A record was kept of all cable splices and has become part of the Quality Assurance file.

With the exception of the splices noted above, no splicing was done in the cable trays at the time of the original installation.

Any subsequent splices or modifications to this cabling will be installed in accordance with approved procedures to minimize the possibility of fires and to meet environmental qualification requirements.

For fire protection details on electrical cabling and equipment refer to Section 8.5.5.

8.5.2 A-C Emergency Power System

The a-c emergency power system includes power supplies, a distribution system, and load groups arranged to provide a-c power to Class 1E loads.

8.5.2.1 Emergency Diesel Generators

The system has two 4,160 v, three phase, 60 Hz diesel-driven synchronous generators, as shown in Figure 8.1-1. The two generator sets are electrically and physically isolated from each other. The diesel generators are supplied by Bruce GM Diesel and were identical with those furnished to James A. Fitzpatrick, Maine Yankee, Connecticut Yankee, Surry 1 and 2, Monticello and Brown's Ferry Nuclear Power Stations (at the time of BVPS-1 operating license issuance).

Each emergency diesel generator is selected and sized in accordance with Regulatory Guide 1.9 (formerly Safety Guide 9) as described in Section 1.3.3.9, and is rated as follows:

2,600 kW - 8,760 hr/yr (continuous)

2,850 kW - 2,000 hr/yr

2,950 kW - 168 hr/yr

3,050 KW - 1/2 hr/yr

In sizing the emergency diesel generators, a complete analysis of the engineered safety features loads, including their required time of operation, length of time required and the required running load, was performed. A reanalysis was performed to better define the loads and re-evaluate the maximum loading of diesel generator No. 1. The EDG loading analysis is part of the electrical calculation program which evaluates the impact of load changes.

The diesel generator loading sequences are designed to pick up loads in steps with adequate intervals between steps to permit inrush currents to subside prior to starting the next block of loads. The diesel generators use a stepped loading sequence to assure starting of emergency bus motors during required accident conditions. The time intervals between successive steps has been selected to assure full voltage output prior to the next successive load step. An emergency diesel generator transient analysis was done to evaluate the capability of each emergency diesel generator to accelerate and continue to operate major emergency loads during sequential loading. This analysis is a part of the electrical calculation program that will evaluate the impact of any changes to emergency diesel generator loading.

To ensure that power to the emergency diesel generator load sequence control circuits is not lost when: the 120V AC vital bus inverter is out of service and bypassed with the 480/120V vital bus alternate transformer; offsite power is not available; and the generator has started to provide power to the 4,160V and 480V emergency bus loads, the source of power will be supplied through two breakers that do not have undervoltage protection. Therefore, when the emergency diesel generator starts, and its output breaker has closed, there will be power available to operate the load sequencer through the entire program.

Each diesel generator is up to speed and capable of accepting loads within ten seconds and energizes designated loads in a stepped sequence within an additional 60 seconds.

Each diesel generator is capable of powering the engineered safety features equipment required (Section 6) following a Design Basis Accident (DBA) as defined in Section 14.3. In the operational mode following a DBA, the inherent capability of each generator unit provides step load starting surge currents and final steady state load carrying margins of at least ten percent above the demand requirements. The diesel generator loads do not exceed the smaller of the 2,000 hour rating (2,850 kW) or 90 percent of the 30 minute rating (0.9 x 3,050 kW = 2,745 kW). Because of the inherent overload capability of the emergency diesel generators and because the maximum connected starting load is a fixed quantity, no additional capacity margin is required in addition to the conservatism included in the determination of loads and hence, any criteria for additional capacity margin are arbitrary. It is therefore concluded that the step load sequence of the diesel generators meets the intent of Regulatory Guide 1.9.[4]

A review of diesel generator power and control circuits' separation by fire area has been conducted in accordance with 10CFR50 Appendix R to ensure that a single fire will not disable both Emergency Diesel Generators. As a result of this review modifications have been made to the original diesel generator control circuits; and cables and equipment core have been relocated to bring the diesel generator circuits into compliance with Appendix R. The modifications included relocation of Emergency Diesel Generator-2 differential protection relays and fuel transfer pump relays, rerouting of Emergency Diesel Generator-1 and -2 field flash cables, and installation of isolation relays and circuit breakers to disconnect non-essential engine controls in the event of fire-induced cable faults in the affected circuits.

With these modifications at least one diesel generator will remain unaffected or recoverable by operating procedure, in the event of an Appendix R design basis fire.

8.5.2.2 Diesel Generator Starting Reliability

The diesel generator set is capable of starting and accepting loads with a 0.99 reliability at the 95 percent confidence level. A diesel generator target reliability of 97.5 percent has been designated in accordance with the NUMARC 87-00 document entitled "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors".[8,9] NUMARC 87-00 has been endorsed by the NRC as an acceptable means of satisfying the Station Blackout Rule - 10 CFR 50.63. If diesel generator performance falls below the target reliability level specified, actions will be taken to restore the target reliability level in accordance with guidance contained in Appendix D of the NUMARC 87-00 document. Furthermore, the diesel generator is designed for nuclear power plant service and has included in its system certain redundant subsystems and highly reliable components.

The diesel generator sets were given a 100 start test at the factory. If any two failures had occurred, the test would have to begin again. However, only one failure to start occurred on the first attempt for the first diesel generator set due to a pinion abutment, and no failures occurred on the first attempt for the second diesel generator set.

Preoperational tests involved fast start and accepting loads per the diesel loading sequence described above. Also, at least once a month, one set will be started manually, synchronized with the system, and run for a period of time furnishing rated power to the system.

It is concluded that the diesel generators will start and accept loads based on design for nuclear service and load data given to the vendor. The diesel generator sets have been tested at the factory to demonstrate the 99 percent reliability as described

above and further to start and accept continuous load and 1/2 hr load rating.

To ensure electrical starting system integrity, the diesel generators are periodically started and exercised in accordance with IEEE Std. 308-1971.[2] (Refer to Table 8.6-1).

8.5.2.3 Diesel Generator Auxiliary Systems

To assure fast, reliable starting and reliable operation, the diesel generators are equipped with certain redundant subsystems and auxiliary equipment. To maintain a high starting reliability, the emergency diesel generators are equipped with 15 kW immersion heaters which supply heat to the engine cooling water when the diesel engines are shut down. Heated water is circulated by thermosiphonic action. Lubricating oil is heated between 125 and 155°F by the flow of this hot water passing through the oil cooler. The warmed oil is circulated through the engine and turbocharger by the lube oil circulating pump and the soak back oil pump and is then returned to the engine oil sump. A lube oil temperature switch will sound an alarm and light an indicator on the engine control cabinet if the oil temperature drops to 115°F.

Each emergency diesel is provided with a starting system sized for five generator starts without outside power. The air dryers for each emergency diesel generator air compressor ensure the reliability of the emergency diesel generator air start system.

Each emergency diesel generator has a fuel oil system, a discussion of which can be found in Section 9.14. The two fuel oil storage tanks are sized for approximately seven days full load operation of one diesel generator. The tanks are buried and covered with a two foot thick concrete slab for missile protection. The fuel oil piping outside the diesel generator building is also buried and covered with a two foot thick concrete slab for missile protection. In addition, the lines from each tank are separated from one another by a concrete partition. Two motor-driven fuel oil transfer pumps (one standby) are available for each diesel engine.

All electrical auxiliary pumps and motors associated with the safety related function of the emergency diesel generators are fed from the emergency buses.

Each emergency diesel generator is provided with two 750 watt strip heaters located below the diesel generator windings. The heaters keep the windings free of moisture when the diesel generator is not in service. The heaters are powered from a non-safety related bus.

8.5.2.4 Diesel Generator Building

The emergency diesel generators are located in a building designed to withstand earthquakes and to protect the diesel generators

against tornadoes, hurricanes, flying missiles, flooding, etc. Within the protected building, the emergency diesel generators, including associated starting equipment and other auxiliaries, are completely isolated from one another by means of a reinforced concrete wall. Cooling water piping to the A diesel generator heat exchanger EE-E-1A passes through the B diesel generator room. This cooling water piping is designed to withstand a failure of the diesel generator and other auxiliaries which may result in a missile impact to the piping system. Each unit is provided with a separate missile protected air intake, air discharge, and engine exhaust. All equipment inside the diesel generator building is Seismic Category I except the normally empty, non-pressurized CO_2 fire lines and roof drain line, and electric unit heaters. However, this equipment is seismically supported so that its failure will not cause failure of the Seismic Category I equipment.

The ambient air temperature in the diesel generator building is maintained at a minimum of 65°F by electric space heaters. The temperature and air supply in the diesel generator building is controlled by four dampers located above the access door to each diesel compartment. The control of the damper operator is achieved through the room thermostats controlling the fan. A rise in space temperature above the thermostat setpoint will cause the damper to open when the fan starts, and conversely, a fall in space temperature will cause the damper to close when the fan stops. Each of the four outdoor air intake dampers includes an emergency powered motor operator so that any single failure will not preclude the opening of the redundant damper, thus assuring that a combustible air supply is available for the diesel generator. The operation of the dampers is verified during periodic starting of the diesel engines to assure that they will operate properly as intended.

Since the Design Basis Accident (DBA) and loss of offsite power, assumed to occur at the same time, would result in a requirement for maximum reliability of the onsite power system, the CO_2 fire protection system serving the diesel generator rooms is automatically deactivated during a DBA to ensure maximum reliability of the onsite power system. Modifications have been made to the CO_2 fire protection system control circuits to preclude spurious CO_2 actuations due to postulated fire induced faults external to the diesel generator rooms.

The diesel generators are separated by a 12 inch thick reinforced concrete wall and two back-to-back doors that provide access between the diesel generator compartments. The wall and doors serve as a protective barrier between the diesel generators. The wall and doors have been analyzed for the accidents discussed below:

A Crankcase Explosion with the Crankcase Door Acting as a Missile

In the event of a crankcase explosion, the crankcase door may be dislodged and propelled toward the reinforced concrete wall, which is 12 ft away from the crankcase housing. In a preliminary

calculation, it was calculated that a pressure of 215 psig was necessary to dislodge the crankcase door. The resulting nine pound missile will impact the wall at a velocity of 420 ft per second. Using the most conservative Ballistic Research Laboratory Missile Penetration formula (Ref. ORNL-NSIC-22), it was shown that the maximum penetration by the crankcase door missile is three inches. Therefore, the 12 inch reinforced concrete wall is adequate to terminate the flight of the crankcase door missile.

The normal operating pressure in the diesel engine crankcase for the emergency diesel generators is 2 to 7 inches H_2O vacuum with a 4 inch water vacuum average. The crankcases have been supplied with high pressure alarms with setpoints of 1 to 1.7 inches water gauge. According to the diesel generator manufacturer a pressure of 89 psig is required to blow off the crankcase door. Assuming no venting from the diesel generator compartment, the 121 cu ft of crankcase volume will vent into the 24,050 cu ft compartment volume without causing compartment pressure to reach 0.8 psig, the minimum pressure which could be considered to dislodge the compartment door. Thus the value of 215 psig used for the above calculation is extremely conservative.

The diesel generators are located so that crankcase door missiles will not be propelled toward the door separating the two diesel generator compartments.

Failure of One or All of the Air Bottles With Missile Generations from the Bottles

Failure of diesel generator starting air bottles is not considered credible. The air bottles contain air at 200 psig and are provided with three pressure controlling devices to prevent overpressurization. The bottle air supply line contains a pressure control, which is set at 200 psig. Also, each bottle is provided with an individual relief valve on the bottle. Finally, the main air supply to the bottles contains a relief valve. Thus, overpressurization of the air bottles will not occur.

A Diesel Oil Fire in One of the Two Compartments Involving Approximately 1,000 Gallons of Fuel Oil

The 12 inch reinforced concrete wall between the diesel generator compartments has a fire rating in excess of four hours as measured by the "Standard Fire Test" defined in report ASTM Std. E119-1981.[5]

The 3 by 7 foot doors between diesel generator compartments has a three hour fire rating as defined by ASTM Std. E152-1980.[6] The maximum rise in temperature on the exposed surface will be less than 250°F within 30 minutes of exposure.

A diesel oil fire would be extinguished by actuation of the CO_2 fire protection system within the time span required for structural deterioration of the reinforced concrete wall and labeled door.

A containment isolation phase B signal (Section 7), also trips the bus tie breaker that isolates the short bus section to which non-engineered safety feature pumps are connected so as to protect against an overload of the respective emergency diesel generator. Each emergency stub bus tie breaker receives the containment isolation phase B (CIB) signal from only one train. If the stub bus fails to trip on a CIB signal one of the following conditions would exist:

1. If a CIB signal occurs without a loss of power and the non-emergency bus does not trip, there would not be an overload on the diesel generators, since the normal 4 kv bus will supply the load.

2. If a CIB signal and loss of power occur simultaneously and the stub bus tie breaker fails to trip, the diesel may be overloaded and trip. However, on a single failure criteria, it can be assumed that the other diesel generator will permit a safe shutdown.

However, the diesel generator that may have tripped on overload can be restarted after a manual trip of the stub bus tie breaker or the other non-essential breakers on the stub bus are tripped.

Redundant power sources, circuit breakers, and relays are physically separated by masonry walls or metal barriers. Cabling is installed to preserve the independence of redundant circuits, as described in Section 7.2.

The same criteria apply to the circuits which shed the non-essential loads.

The independence between redundant standby (emergency) power sources and between their distribution systems is in accordance with AEC Safety Guide 6 as discussed in Section 1.3.3.6.

The emergency diesel generator and the normal station service are synchronized only for the following two conditions:

1. Periodic testing.

2. Return of the emergency bus to the normal station service supply following a loss of offsite power occurrence with subsequent restoration of offsite power.

This synchronizing is done manually and automatic synchronizing is not supplied.

All engineered safety feature equipment items are duplicated and connected to separate 4,160 v and 480 v emergency buses. (Refer to Figures 8.1-1 and 8.4-1

for the electrical one line diagrams.) All duplicated safety related equipment is connected to separate buses. If there is a third redundant piece of equipment, it is normally not connected to either emergency bus, but it can be manually connected to either one as described below.

Three 4 kv pump motors, each of which is a third redundant swing unit, (one charging pump, one river water pump, and one primary component cooling water pump) may be supplied from either 4 kv bus (Figure 8.1-1). Dual feeds for these pumps do not form a bus tie because only one of the two breaker cubicles will have a circuit breaker installed at any time. The second redundant 4 kv cubicle of a 4 kv motor will have no circuit breaker installed.

A mechanical key interlock system shown in Figure 8.5-8, is provided to ensure that only one circuit breaker for the dual feed motor can be put into the operating position at one time.

Two 480 v motor circuits, each of which is a third redundant swing unit (one shroud fan motor and one containment air recirculation fan) may be supplied from either 480 v bus (Figure 8.1-1). Each 480 v ACB cubicle is occupied by an ACB unless a breaker is out for maintenance, repair or temporarily used in another location. The load side of each of these ACB on a dual fed circuit is connected to a three pole double throw switch provided and connected as shown in Figure 8.1-1. Because of the three pole double throw switch, the dual feeds for either of these circuits can not form a bus tie. Only one of the two breakers is in the operating position at a given time. The breaker which is not required to operate is locked in the disconnect position (breaker insertion is mechanically prohibited).

Selection of the operating breaker on a third redundant swing unit depends on station requirements and is under administrative control. This arrangement of dual feed, third redundant units, allows maintenance to be performed on any of the units while satisfying single failure criteria.

If any engineered safety features equipment fails to operate automatically, remote manual operation is possible from the main control room. The switchgear sections for each emergency diesel generator are physically and electrically isolated from each other as shown on Figure 8.5-1.

If the loss of normal power is not accompanied by a loss-of-coolant accident, the engineered safety features equipment is not required. Under this condition, other unit auxiliary equipment (e.g., primary component cooling water pump, residual heat removal pump, etc.), may be operated up to the capacity of the emergency diesel generators. Instrumentation is provided to indicate diesel generator loading.

Each piece of engineered safety features equipment is connected to the emergency power with an exclusive circuit. Each circuit has an air switchgear circuit breaker with overcurrent protection, and