PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

TS 6.17.d (Unit 1)
TS 6.16.d (Unit 2)

LR-N07-0251

OCT 17 2007

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

Salem Generating Station, Units 1 and 2
Facility Operating License Nos. DPR-70 and DPR-75
NRC Docket Nos. 50-272 and 50-311

Subject: Submittal of Changes to Technical Specifications Bases

In accordance with the requirements of Salem Generating Station, Units 1 and 2 Technical Specifications 6.17.d (Unit 1) and 6.16.d (Unit 2), PSEG Nuclear LLC (PSEG) hereby submits a complete updated copy of the Unit 1 and Unit 2 Technical Specifications Bases, which includes changes through the date of this letter.

If you have any questions or require further information, please contact Paul Duke (856-339-1466).

Sincerely,

Jeffrie Keenan
Manager - Licensing

Attachments (2)
1. Salem Unit 1 TS and Bases
2. Salem Unit 2 TS and Bases

cc: S. Collins, Regional Administrator – NRC Region I
R. Ennis, Project Manager - Salem, USNRC
NRC Senior Resident Inspector - Hope Creek
P. Mulligan, Manager IV, NJBNE

A001

NRR

ATTACHMENT 1

Salem Generating Station, Unit 1

Facility Operating License No. DPR-70
NRC Docket No. 50-272

Salem Unit 1 TS and Bases

ATTACHMENT 2

Salem Generating Station, Unit 2

Facility Operating License No. DPR-75
NRC Docket No. 50-311

Salem Unit 2 TS and Bases

OPERATING LICENSE

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ADDITIONAL CONDITIONS OPERATING LICENSE No. DPR-70 <u>APPENDIX C</u>

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* PSEG Issued

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

PSEG NUCLEAR LLC
EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-272

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

FACILITY OPERATING LICENSE

Amendment No. 246
License No. DPR-70

1. The Nuclear Regulatory Commission (the Commission) having found that:

   A. The application for license filed by the Public Service Electric and Gas Company, Philadelphia Electric Company, Delmarva Power and Light Company, and Atlantic City Electric Company and the application for license amendment dated November 8, 1976, filed by Public Service Electric and Gas Company comply with the standards and requirements of the Atomic Energy Act (the Act) of 1954, as amended, and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the Salem Nuclear Generating Station, Unit No. 1 (facility) has been substantially completed in conformity with Provisional Construction Permit No. CPPR-52 and the application, as amended, the provisions of the Act and regulations of the Commission;

   C. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

   D. There is reasonable assurance: (i) that the activities authorized by this amended operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

   E. PSEG Nuclear LLC is technically qualified and the licensees are financially qualified to engage in the activities authorized by this amended operating license in accordance with the rules and regulations of the Commission;

F. The licensees have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

G. The issuance of this amended operating license will not be inimical to the common defense and security or to the health and safety of the public;

H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Amendment No. 3 to Facility Operating License No. DPR-70, subject to the conditions for protection of the environment set forth in the Technical Specifications, Appendix B is in accordance with 10 CFR Part 51 (and with former Appendix D to 10 CFR Part 50) of the Commission's regulations and all applicable requirements have been satisfied; and

I. The receipt, possession, and use of source, byproduct and special nuclear material as authorized by this amended license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40, and 70 including 10 CFR Sections 30.33, 40.32, and 70.23 and 70.31.

2. Facility Operating License No. DPR-70, issued to PSEG Nuclear LLC, and Exelon Generation Company LLC (Exelon Generation Company), (the licensees), is hereby amended in its entirety, to read as follows:

A. This amended license applies to the Salem Nuclear Generating Station, Unit No. 1, a pressurized water nuclear reactor and associated equipment (the facility), owned by PSEG Nuclear LLC and the Exelon Generation Company, and operated by PSEG Nuclear LLC. The facility is located on the applicants' site in Salem County, New Jersey, on the southern end of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, and is described in the "Final Safety Analysis Report" as supplemented and amended (Amendments 10 through 39) and the Environmental Report as supplemented and amended (Amendments 1 through 3).

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses

(1) PSEG Nuclear LLC, and the Exelon Generation Company to possess the facility at the designated location in Salem County, New Jersey, in accordance with the procedures and limitations set forth in this amended license;

(2) PSEG Nuclear LLC, pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use and operate the facility;

(3) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70 to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70 to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate the facility at a steady state reactor core power level not in excess of 3459 megawatts (one hundred percent of rated core power).

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 283, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Deleted Per Amendment 22, 11-20-79

(4) Less than Four Loop Operation

PSEG Nuclear LLC shall not operate the reactor at power levels above P-7 (as defined in Table 3.3-1 of Specification 3.3.1.1 of Appendix A to this license) with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensees and approval for less than four loop operation at power levels above P-7 has been granted by the Commission by Amendment of this license.

(5) PSEG Nuclear LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report, and as approved in the NRC Safety Evaluation Report dated November 20, 1979, and in its supplements, subject to the following provision:

PSEG Nuclear LLC may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(6) The licensee shall implement a secondary water chemistry monitoring program to inhibit steam generator tube degradation. This program shall include:

1. Identification of a sampling schedule for the critical parameters and control points for these parameters;

2. Identification of the procedures used to measure the values of the critical parameters;

3. Identification of process sampling points;

4. Procedure for recording and management of data;

5. Procedures defining corrective actions for off control point chemistry conditions; and

6. A procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

(7) Systems Integrity

The licensee shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic inspection requirements, and

2. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

(8) Iodine Monitoring

The licensee shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel;

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

(9) Backup Method for Determining Subcooling Margin

The licensee shall implement a program which will ensure the capability to accurately monitor the Reactor Coolant System subcooling margin. This program shall include the following:

1. Training of personnel, and

2. Procedures for monitoring.

(10) Additional Conditions

The Additional Conditions contained in Appendix C, as revised through Amendment No. 246, are hereby incorporated into this license. PSEG Nuclear LLC shall operate the facility in accordance with the Additional Conditions.

(11) PSE&G to PSEG Nuclear LLC License Transfer Conditions

a. PSEG Nuclear LLC shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application, the requirements of the Order Approving Transfer of License and Conforming Amendment, dated February 16, 2000, and the related Safety Evaluation dated February 16, 2000.

b. The decommissioning trust agreement shall provide that:

1) The use of assets in both the qualified and non-qualified funds shall be limited to expenses related to decommissioning of the unit as defined by the NRC in its regulations and issuances, and as provided in the unit's license and any amendments thereto. However, upon completion of decommissioning, as defined above, the assets may be used for any purpose authorized by law.

2) Investments in the securities or other obligations of PSE&G or affiliates thereof, or their successors or assigns, shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants shall be prohibited.

3) No disbursements or payments from the trust shall be made by the trustee until the trustee has first given the NRC 30 days notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation.

4) The trust agreement shall not be modified in any material respect without prior written notification to the Director, Office of Nuclear Reactor Regulation.

5) The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(3) of the Federal Energy Regulatory Commission's regulations.

c. PSEG Nuclear LLC shall not take any action that would cause PSEG Power LLC or its parent companies to void, cancel, or diminish the commitment to fund an extended plant shutdown as represented in the application for approval of the transfer of this license from PSE&G to PSEG Nuclear LLC.

(12) Exelon Generation Company shall provide to the Director of the Office of Nuclear Reactor Regulation a copy of any application, at the time it is filed, to transfer (excluding grants of security interests or liens) from Exelon Generation Company to its direct or indirect parent, or to any other affiliated company, facilities for the production, transmission, or distribution of electric energy having a depreciated book value exceeding ten percent (10%) of Exelon Generation Company's consolidated net utility plant, as recorded on Exelon Generation Company's books of account.

(13) Exelon Generation Company shall have decommissioning trust funds for Salem, Unit 1, in the following minimum amount on the closing date of the license transfer:

Salem, Unit 1	$53,780,652

(14) The decommissioning trust agreement for Salem, Unit 1, shall be subject to the following:

(a) The decommissioning trust agreement must be in a form acceptable to the NRC.

(b) With respect to the decommissioning trust fund, investments in the securities or other obligations of Exelon Corporation or affiliates thereof, or their successors or assigns are prohibited. Except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants are prohibited.

(c) The decommissioning trust agreement for Salem, Unit 1, must provide that no disbursements or payments from the trust shall be made by the trustee unless the trustee has first given the Director of the Office of Nuclear Reactor Regulation 30 days prior written notice of payment. The decommissioning trust agreement shall further contain a provision that no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the NRC.

(d) The decommissioning trust agreement must provide that the agreement can not be amended in any material respect without 30 days prior written notification to the Director of the Office of Nuclear Reactor Regulation.

(e) The appropriate section of the decommissioning trust agreement shall state that the trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations.

(15) Exelon Generation Company shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for approval of the transfer of the Salem, Unit 1, license to it and the requirements of the Order approving the transfer, and consistent with the safety evaluation supporting the Order.

(16) Mitigation Strategy

The licensee shall develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:

1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:

1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:

1. Water spray scrubbing
2. Dose to onsite responders

D. Paragraph 2.D. has been combined with paragraph 2.E. per Amendment No. 86, June 27, 1988.

E. The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, submitted by letter dated May 19, 2006, are entitled: "Salem-Hope Creek Nuclear Generating Station Security Plan," "Salem-Hope Creek Nuclear Generating Station Security Training and Qualification Plan," and "Salem-Hope Creek Nuclear Generating Station Security Contingency Plan." The plans contain Safeguards Information protected under 10 CFR 73.21.

F. In accordance with the requirement imposed by the October 8, 1976, order of the United States Court of Appeals for the District of Columbia Circuit in Natural Resources Defense Council v. Nuclear Regulatory Commission, No. 74-1385 and 74-1586, that the Nuclear Regulatory Commission "shall make any licenses granted between July 21, 1976 and such time when the mandate is issued subject to the outcome of the proceedings herein," the license amendment issued herein shall be subject to the outcome of such proceedings.

G. Prior to startup following the first regularly scheduled refueling outage, Public Service Electric and Gas Company shall install, to the satisfaction of the Commission, a long-term means of protection against reactor coolant system over-pressurization when water-solid.

H. This amended license is effective as of the date of its issuance. Facility Operating License No. DPR-70, as amended, shall expire at midnight, August 13, 2016.

I IAEA SAFEGUARDS

1. INCORPORATION OF FACILITY ATTACHMENT:

Pursuant to 10 CFR 75.8, NRC License No. DPR-70 is hereby amended to incorporate by reference Codes 1. through 7. of Facility Attachment No. 13 dated October 1, 1986, to the US/IAEA of Safeguards Agreement.

2. FACILITY ATTACHMENT CODE 2.2

Notification of the changes referred to in Code 2.2 of the facility attachment is the responsibility of the operating facility. They can be notified to the NRC with a Concise Note (DOE/NRC Form 740M) or a letter. Notification is required 70 days prior to the event.

3. FACILITY ATTACHMENT CODE 3.1.3 & 5.1.2 & 5.2.3

The itemized lists of nuclear material to be provided to the IAEA as of cycle shutdown date prior to physical inventory taking are:

1. A complete list of fuel assemblies by ID number at all locations.

2. Reactor and fuel storage maps showing location of fuel by ID number at time of physical inventory taking.

3. A list, by batch, of any other accountable nuclear material, e.g., start-up sources, samples.

4. FACILITY ATTACHMENT CODE 3.2.2

Please refer to NRC letter dated May 27, 1986, to Mr. C.A. McNeill from Steven A. Varga which spells out timeliness and procedures for notification under this code.

5. FACILITY ATTACHMENT CODE 5.1.1 & 6.1.1

The statement "when calculated" means at least as often as required on page 2 of NUREG/BR-0006 Revision 2 or more often, at your option, if you calculate burn up more than every six months.

6. FACILITY ATTACHMENT CODE 6.1.1 & 6.1.2

The phrase "as specified in relevant paragraphs of Code 10" is a requirement on the U.S. All of the paragraphs in the US/IAEA Agreement that require a report from the U.S. to the IAEA based on source data from an operating facility have been incorporated into NUREG's BR-0006 and 0007 so that the NRC may collect the needed data for transmittal to the IAEA. PSEG Nuclear LLC should follow these NUREGs precisely in reporting inventory changes. A complete response to the reporting instructions in the NUREGs will satisfy the requirements specified in Code 10.

7. FACILITY ATTACHMENT CODE 6.2.2

The phrase "precise forecasts" means best estimates. These required concise notes should be dispatched to the NRC at least 40 days in advance of a projected 6 month operational programming.

8. FACILITY ATTACHMENT CODE 6.3.1 & 6.3.2

See response to Code 6.1.1 and 6.1.2 above.

9. FACILITY ATTACHMENT CODE 7.9

The specific facility health and safety rules and regulations to be observed by the Agency's (IAEA) inspectors, as specified in Paragraph 54 of the design information as of October 10, 1986, provided by the U.S.A. mean:

Agency inspectors who have previously visited the facility will be informed as necessary at the time of entry into the facility of health and safety rules and *ad hoc* rules as might be required in view of a special situation that has occurred at the facility since the inspector's last visit to the facility. The briefing will be of a short duration, not to exceed 30 minutes, covering topics deemed relevant by the licensee.

Agency inspectors who have not previously visited the facility will be informed as necessary at the time of entry into the facility of health and safety rules and *ad hoc* rules as might be required in view of a special situation that has occurred at the facility. The briefing will be of an appropriate duration, not to exceed three hours, and consist of topics deemed relevant by the licensee.

In either case, the licensee should take into account the Agency inspector's prior training, expertise and experience. In neither case shall the Agency inspector be subject to any form of evaluation or testing by facility representatives or representatives of the U.S. Government.

For health and safety reasons, Agency inspectors will be escorted by qualified facility personnel at times deemed appropriate by the licensee.

10. TERMINATION

Pursuant to the provisions of 10 CFR 75.41, the Commission will inform the licensee, in writing, when its installation is no longer subject to Article 39(b) of the principal text of the US/IAEA Safeguards Agreement. The IAEA Safeguards License Conditions incorporating Code 7.. of the Facility Attachment as part of NRC License DPR-70 will be terminated as of the date of such notice from the Commission. However, since the IAEA may elect to maintain the licensee's installation under Article 2(a) of the Protocol, provisions equivalent to Codes 1. through 6. of the Facility Attachment (with possible appropriate modifications) may still apply, and accordingly all other IAEA Safeguards License Conditions to NRC License No. DPR-70 will remain in effect until the Commission notifies the licensee otherwise. If this option is not selected by the IAEA, the Commission will then notify the licensee that all License Conditions pertaining to the US/IAEA Safeguards Agreement are terminated.

J. RELOCATED TECHNICAL SPECIFICATIONS

PSEG Nuclear LLC shall relocate certain technical specification requirements to licensee-controlled documents as described below. The location of these requirements shall be retained by the licensee.

a. This license condition approves the relocation of certain technical specification requirements to licensee-controlled documents (UFSAR), as described in the licensee's applications with the staff's safety evaluation approval and Amendment No. as noted below:

Licensee's Applications	Safety Evaluations	Amendment Nos.
September 25, 1996	January 0, 1997	189

Implementation shall include the relocation of technical specifications requirements to the appropriate licensee-controlled document as identified in the licensee's application.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by Roger S. Boyd

Roger S. Boyd, Director
Division of Project Management
Office of Nuclear Reactor Regulation

Attachments:
1. Incomplete Preoperational Tests, Startup Tests, and Other Items Which Must Be Completed
2. Page Changes to Technical Specifications, Appendix A

Date of Issuance: December 1, 1976

SECTION PAGE

1.0 DEFINITIONS

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

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LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

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ADMINISTRATIVE CONTROLS

SECTION 1.0

DEFINITIONS

1.0 DEFINITIONS

DEFINED TERMS

1.1 The DEFINED TERMS of this section appear in capitalized type and are applicable throughout these Technical Specifications.

ACTION

1.2 ACTION shall be that part of a specification which prescribes remedial measures required under designated conditions.

AXIAL FLUX DIFFERENCE

1.3 AXIAL FLUX DIFFERENCE shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, display, and trip functions, and shall include the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever an RTD or thermocouple sensing element is replaced, the next required CHANNEL CALIBRATION shall include an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 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.

CONTAINMENT INTEGRITY

1.7 CONTAINMENT INTEGRITY shall exist when:

1.7.1 All penetrations required to be closed during accident conditions are either:

a. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

b. Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except for valves that are open under administrative control as permitted by Specification 3.6.3.1.

1.7.2 All equipment hatches are closed and sealed,

1.7.3 Each air lock is OPERABLE pursuant to Specification 3.6.1.3,

1.7.4 The containment leakage rates are within the limits of Specification 3.6.1.2, and

1.7.5 The sealing mechanism associated with each penetration (e.g., welds, bellows or 0-rings) is OPERABLE.

CORE ALTERATION

1.8 CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe conservative position.

CORE OPERATING LIMITS REPORT

1.9 The CORE OPERATING LIMITS REPORT (COLR) is the unit-specific document that provides core operating limits for the current operating reload cycle. These cycle-specific core operating limits shall be determined for each reload cycle in accordance with Specification 6.9.1.9. Unit operation within these operating limits is addressed in individual specifications.

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of 1-131 (microcuries per gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Federal Guidance Report No. 11 (FGR 11), "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion".

E - AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half-lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

ENGINEERED SAFETY FEATURE RESPONSE TIME

1.12 The ENGINEERED SAFETY FEATURE RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

FREQUENCY NOTATION

1.13 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.2.

FULLY WITHDRAWN

1.13a FULLY WITHDRAWN shall be the condition where control and/or shutdown banks are at a position which is within the interval of 222 to 228 steps withdrawn, inclusive. FULLY WITHDRAWN will be specified in the current reload analysis.

GASEOUS RADWASTE TREATMENT SYSTEM

1.14 A GASEOUS RADWASTE TREATMENT SYSTEM is any system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

IDENTIFIED LEAKAGE

1.15 IDENTIFIED LEAKAGE shall be:

a. Leakage (except Reactor Coolant Pump Seal Water Injection) into closed systems, such as pump seal or valve packing leaks that are captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE, or

c. Reactor coolant system leakage through a steam generator to the secondary system (primary-to-secondary leakage).

MEMBER(S) OF THE PUBLIC

1.16 MEMBER(S) OF THE PUBLIC shall be all those persons who are not occupationally associated with the plant. This category does not include employees of PSE&G, its contractors, or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational, or other purposes not associated with the plant.

OFFSITE DOSE CALCULATION MANUAL (ODCM)

1.17 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent controls and Radiological Environmental Monitoring programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.9.1.7 and 6.9.1.8 respectively.

OPERABLE - OPERABILITY

1.18 A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

OPERATIONAL MODE - MODE

1.19 An OPERATIONAL MODE (i.e., MODE) shall correspond to any one inclusive combination of core reactivity condition, power level and average reactor coolant temperature specified in Table 1.1.

PHYSICS TESTS

1.20 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and 1) described in Chapter 14 of the Updated FSAR, 2) authorized under the provisions of 10CFR50.59, or 3) otherwise by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.21 PRESSURE BOUNDARY LEAKAGE shall be leakage (except primary-to-secondary leakage) through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.22 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of radioactive waste.

PURGE - PURGING

1.23 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

QUADRANT POWER TILT RATIO

1.24 QUADRANT POWER TILT RATIO shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.25 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3459 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor
until loss of stationary gripper coil voltage.

REPORTABLE EVENT

1.27 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10CFR Part 50.

SHUTDOWN MARGIN

1.28 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be FULLY WITHDRAWN.

SITE BOUNDARY

1.29 The SITE BOUNDARY shall be that line beyond which the land is not owned, leased, or otherwise controlled by the licensee, as shown in Figure 5.1-3, and which defines the exclusion area as shown in Figure 5.1-1.

SOLIDIFICATION

1.30 Not Used

SOURCE CHECK

1.31 SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to either (a) an external source of increased radioactivity, or(b) an internal source of radioactivity (keep-alive source), or (c) an equivalent electronic source check.

STAGGERED TEST BASIS

1.32 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for (n) systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into (n) equal subintervals.

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

THERMAL POWER

1.33 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

UNIDENTIFIED LEAKAGE

1.34 UNIDENTIFIED LEAKAGE shall be all leakage (except Reactor Coolant Pump Seal Water Injection) which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.35 An UNRESTRICTED AREA shall be any area at or beyond the SITE BOUNDARY, access to which is not controlled by the licensee for purposes of protection of individuals from exposure to radiation and radioactive materials, or any area within the SITE BOUNDARY used for residential quarters or industrial, commercial, institutional, and/or recreational purposes.

VENTILATION EXHAUST TREATMENT SYSTEM

1.36 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine and radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.37 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

TABLE 1.1

OPERATIONAL MODES

MODE	REACTIVITY CONDITION, K_{eff}	THERMAL POWER*	AV RAGE COOLANT TEMPERATURE
1. POWER OPERATION	$\geq$ 0.99	> 5%	$\geq$ 350°F
2. STARTUP	$\geq$ 0.99	$\leq$ 5%	$\geq$ `50°F
3. HOT STANDBY	< 0.99	0	$\geq$ 350°F
4. HOT SHUTDOWN	< 0.99	0	350°F > T_{avg} > 200°F
5. COLD SHUTDOWN	< 0.99	0	$\leq$ 200°F
6. REFUELING**	$\leq$ 0.95	0	$\leq$ 140°F

* Excluding decay heat.

** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 6 months.
R	At least once per 18 months.
S/U	Prior to each reactor startup.
P	Prior to each release.
N.A.	Not applicable.

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and the highest operating loop coolant temperature (T_{avg}) shall not exceed the limits shown in Figure 2.1-1 for 4 loop operation.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of the highest operating loop average temperature and THERMAL POWER has exceeded the appropriate pressurizer pressure line, be in HOT STANDBY within 1 hour.

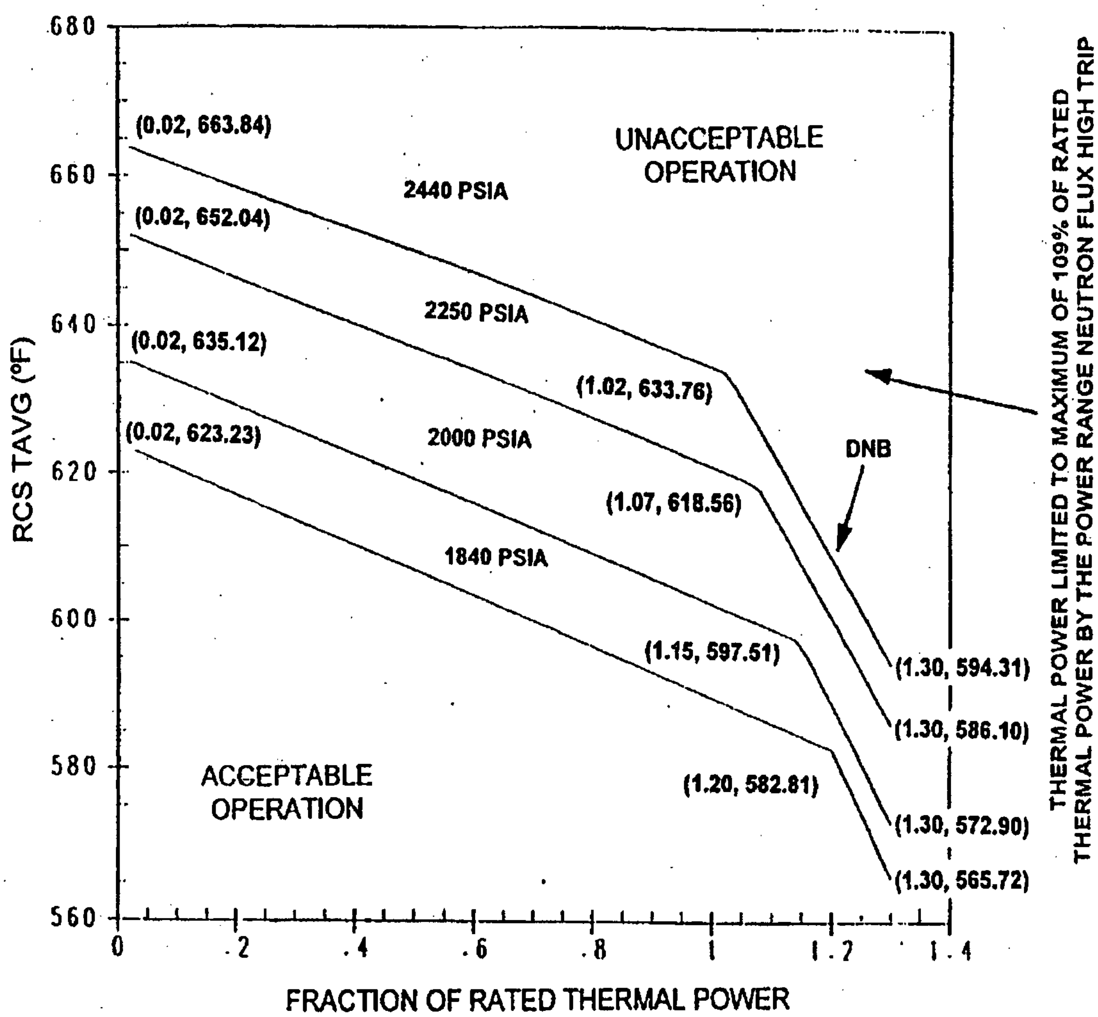

FIGURE 2.1-1
REACTOR CORE SAFETY LIMIT - FOUR LOOPS IN OPERATION

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2735 psig.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor trip system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: As shown for each channel in Table 3.3-1.

ACTION:

With a reactor trip system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Range, Neutron Flux	Low Setpoint - ≤ 25% of RATED THERMAL POWER High Setpoint - ≤ 109% of RATED THERMAL POWER	Low Setpoint - ≤ 26% of RATED THERMAL POWER High Setpoint - ≤ 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Deleted		
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 counts per second	≤ 1.3 x 10^5 counts per second
7. Overtemperature ΔT	See Note 1	See Note 3
8. Overpower ΔT	See Note 2	See Note 4
9. Pressurizer Pressure--Low	≥ 1865 psig	≥ 1855 psig
10. Pressurizer Pressure--High	≤ 2385 psig	≤ 2395 psig
11. Pressurizer Water Level--High	≤ 92% of instrument span	≤ 93% of instrument span
12. Loss of Flow	≥ 90% of design flow per loop*	≥ 89% of design flow per loop*

* Design flow is 82,500 gpm per loop.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level--Low-Low	≥ 14.0% of narrow range instrument span-each steam generator	≥ 13.0% of narrow range instrument span-each steam generator
14. Deleted		
15. Undervoltage-Reactor Coolant Pumps	≥ 2900 volts-each bus	≥ 2850 volts-each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 56.5 Hz - each bus	≥ 56.4 Hz - each bus
17. Turbine Trip		
A. Low Trip System Pressure	≥ 45 psig	≥ 45 psig
B. Turbine Stop Valve Closure	≤ 15% off full open	≤ 15% off full open
18. Safety Injection Input from ESF	Not Applicable	Not Applicable
19. Reactor Coolant Pump Breaker Position Trip	Not Applicable	Not Applicable

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION

NOTE 1: Overtemperature $\Delta T \leq \Delta T_o \left[K_1 - K_2\left(\frac{1+\tau_1 S}{1+\tau_2 S}\right)(T-T') + K_3(P-P') - f_1(\Delta I)\right]$

where: ΔT_o = Indicated ΔT at RATED THERMAL POWER

T = Average temperature, °F

T' = Indicated T_{avg} at RATED THERMAL POWER $\leq$ 577.9°F

P = Pressurizer pressure, psig

P' = 2235 psig (indicated RCS nominal operating pressure)

$\frac{1+\tau_1 S}{1+\tau_2 S}$ = The function generated by the lead-lag controller for T_{avg} dynamic compensation

τ_1 & τ_2 = Time constants utilized in the lead-lag controller for T_{avg} τ_1 = 30 secs ±10%, τ_2 = 4 secs. ±10%

S = Laplace transform operator, Sec $^{-1}$

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

Operation with 4 Loops

K1 = 1.22
K2 = 0.02037
K3 = 0.001020

and f_1 (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -33 percent and +11 percent, f_1 (ΔI) = 0 (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of ($q_t - q_b$) exceeds -33 percent, the ΔT trip setpoint shall be automatically reduced by 2.34 percent of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of ($q_t - q_b$) exceeds +11 percent, the ΔT trip setpoint shall be automatically reduced by 2.37 percent of its value at RATED THERMAL POWER.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 2: Overpower: $\Delta T \leq \Delta T_o \{K_4 - K_5\left[\frac{\tau_3 S}{1 + \tau_3 S}\right]T - K_6(T - T") - f_2(\Delta I)\}$

where: ΔT_o = Indicated ΔT at RATED THERMAL POWER

T = Average temperature, °F

$T"$ = Indicated T_{avg} at RATED THERMAL POWER ≤ 577.9°F

K_4 = 1.09

K_5 = 0.02/°F for increasing average temperature and 0 for decreasing average temperature

K_6 = 0.00149/°F for T > T"; K_6 = 0 for T ≤ T"

$\frac{\tau_3 S}{1+\tau_3 S}$ = The function generated by the rate lag controller for T_{avg} dynamic compensation

τ_3 = Time constant utilized in the rate lag controller for T_{avg} τ_3 = 10 secs. ±10%

S = Laplace transform operator, Sec^{-1}

$f_2(\Delta I)$ = 0 for all ΔI

NOTE 3: The channel's maximum trip point shall not exceed its computed trip point by more than 1.1 percent.

NOTE 4: The channel's maximum trip point shall not exceed its computed trip point by more than 2.1 percent.

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

NOTE

The summary statements contained in this section provided the bases for the specifications of Section 2.0 and are not considered a part of these technical specifications as provided in 10 CFR 50.36.

BASES

2.1.1 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through correlations which have been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, DNBR, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The DNB design basis is as follows: uncertainties in the WRB-1 and WRB-2 correlations, plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, and computer codes are considered statistically such that there is at least a 95 percent probability with 95 percent confidence level that DNBR will not occur on the most limiting fuel rod during Condition I or II events. This establishes a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties.

The curves of Figure 2.1-1 shows the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the design DNBR value, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

BASES

The curves are based on an enthalpy hot channel factor, $F^{RTP}_{\Delta H}$, and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^{N}_{\Delta H}$ at reduced power based on the expression:

$$F^{N}_{\Delta H} = F^{RTP}_{\Delta H} [1.0 + PF_{\Delta H} (1.0 - P)]$$

where: $F^{RTP}_{\Delta H}$ is the limit at RATED THERMAL POWER (RTP) specified in the Core Operating Limits Report (COLR).

$PF_{\Delta H}$ is the Power Factor Multiplier for $F^{N}_{\Delta H}$ specified in the COLR,

and

P is $\frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

These limiting heat flux conditions are higher than those calculated for the range of all control rod positions from rods FULLY WITHDRAWN to the maximum allowable control rod insertion assuming the axial power imbalance is within the limits of the $f_1(\Delta I)$ function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature ΔT trips will reduce the setpoints to provide protection consistent with core safety limits.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor pressure vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plant which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The Reactor Coolant System piping and fittings are designed to ANSI B 31.1 1955 Edition while the valves are designed to ANSI B 16.5, MSS-SP-66-1964, or ASME Section III-1968, which permit maximum transient pressures of up to 120% (2985 psig) of component design pressure. The Safety Limit of 2735 psig is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at 3107 psig, 125% of design pressure, to demonstrate integrity prior to initial operation.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as-left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy).

The Trip Setpoints used in the bistables are based on the analytical limits stated in the UFSAR. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those Reactor Protection System (RPS) channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints and Allowable Values specified in the Technical Specification Limiting Conditions for Operation (LCO's) are conservatively adjusted with respect to the analytical limits. The methodology used to calculate the Trip Setpoints is consistent with Instrument Society of America standard ISA-S67.04-1982, which is endorsed via NRC Regulatory Guide 1.105, Rev. 2. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the safety analyses which demonstrate that safety limits are not violated remain valid (provided the unit is operated within the LCO's at the onset of any design basis event and the equipment functions as designed).

The Trip Setpoints and Allowable Values listed in the LCO's incorporate all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Power Range, Neutron Flux

The Power Range, Neutron Flux channel high setpoint provides reactor core protection against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The low set point provides redundant protection in the power range for a power excursion beginning from low power. The trip associated with the low setpoint may be manually bypassed when P-10 is active (two of the four power range channels indicate a power level of above approximately 9 percent of RATED THERMAL POWER) and is automatically reinstated when P-10 becomes inactive (three of the four channels indicate a power level below approximately 9 percent of RATED THERMAL POWER).

Power Range, Neutron Flux, High Rate

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of rod ejection events from any power level. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from partial power.

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor core protection during reactor startup. These trips provide redundant protection to the low setpoint trip of the Power Range, Neutron Flux channels. The Source Range Channels will initiate a reactor trip at about 10^{+5} counts per second unless manually blocked when P-6 becomes active. The Intermediate Range Channels will initiate a reactor trip at a current level proportional to approximately 25 percent of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit was taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

Overtemperature Δ T

The Overtemperature Δ T trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors (about 4 seconds), and pressure is within the range between the High and Low Pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. With normal axial power distribution, this reactor trip limit is always below the core safety limit as shown in Figure 2.1-1. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the reactor trip is automatically reduced according to the notations in Table 2.2-1.

Operation with a reactor coolant loop out of service below the 4 loop P-8 set point does not require reactor protection system set point modification because the P-8 set point and associated trip will prevent DNB during 3 loop operation exclusive of the Overtemperature ΔT set point. Three loop operation above the 4 loop P-8 set point has not been evaluated and is not permitted.

Overpower ΔT

The Overpower ΔT reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature ΔT protection, and provides a backup to the High Neutron Flux trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors. No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Pressurizer Pressure

The Pressurizer High and Low Pressure trips are provided to limit the pressure range in which reactor operation is permitted. The High Pressure trip is backed up by the pressurizer code safety valves for RCS overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The Low Pressure trip provides protection by tripping the reactor in the event of a loss of reactor coolant pressure.

Pressurizer Water Level

The Pressurizer High Water Level trip ensures protection against Reactor Coolant System overpressurization by limiting the water level to a volume sufficient to retain a steam bubble and prevent water relief

BASES

through the pressurizer safety valves. No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Loss of Flow

The Loss of Flow trips provide core protection to prevent DNB in the event of a loss of one or more reactor coolant pumps.

Above 11 percent of RATED THERMAL POWER, an automatic reactor trip will occur if the flow in any two loops drop below 90% of nominal full loop flow. Above 36% (P-8) of RATED THERMAL POWER, automatic reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. This latter trip will prevent the minimum value of the DNBR from going below the design DNBR value during normal operational transients.

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip provides core protection by preventing operation with the steam generator water level below the minimum volume required for adequate heat removal capacity. The specified setpoint provides allowance that there will be sufficient water inventory in the steam generators at the time of trip to allow for starting delays of the auxiliary feedwater system.

LIMITING SAFETY SYSTEM SETTINGS

BASES

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The specified set points assure a reactor trip signal is generated before the low flow trip set point is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 0.9 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip setpoint is reached shall not exceed 0.3 seconds.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-9. Each of the turbine trips provide turbine protection and reduce the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

Safety Injection Input from ESF

If a reactor trip has not already been generated by the reactor protective instrumentation, the ESF automatic actuation logic channels will initiate a reactor trip upon any signal which initiates a safety injection. This trip is provided to protect the core in the event of a LOCA. The ESF instrumentation channels which initiate a safety injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The reactor Coolant Pump Breaker Position Trip is an anticipatory trip which provides reactor core protection against DNB resulting from the opening of two or more pump breakers above P-7. This trip is blocked below P-7. The open/close position trip assures a reactor trip signal is generated before the low flow trip set point is reached. No credit was taken in the accident analyses for operation of this trip. The functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Protection System.

3/4 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the limiting Conditions for Operation contained in the succeeding specifications is required during the OPERATIONAL MODES or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the ACTION requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met except as provided in the associated ACTION requirements, within one hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in:

1. At least HOT STANDBY within the next 6 hours,
2. At least HOT SHUTDOWN within the following 6 hours, and
3. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual specifications.

3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time; or

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications, or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

3.0.5 DELETED

3.0.6 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

APPLICABILITY

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL MODES or other specified conditions in the Applicability for individual Limiting Conditions for Operation, unless otherwise stated in the Surveillance Requirement. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the Limiting Condition for Operation. Failure to perform a Surveillance within the specified frequency shall be failure to meet the Limiting Condition for Operation, except as provided in Specification 4.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 Each Surveillance Requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25 percent of the specified surveillance interval.

4.0.3 If it is discovered that a Surveillance was not performed within its specified frequency, then compliance with the requirement to declare the Limiting Condition for Operation not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the Limiting Condition for Operation must immediately be declared not met and the applicable Actions must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the Limiting Condition for Operation must immediately be declared not met and the applicable Actions must be entered.

4.0.4 Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency, except as provided by SR 4.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 and 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

SURVEILLANCE REQUIREMENTS

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days

c. The provision of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - Tavg > 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be ≥ 1.3% Δk/k.

APPLICABILITY: MODES 1, 2*, 3, and 4.

ACTION:

With the SHUTDOWN MARGIN < 1.3% Δk/k, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be ≥ 1.3% Δk/k:

a. Within one hour after detection of an inoperable control rod(s)and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable control rod(s).

b. When in MODES 1 or 2#, at least once per 12 hours by verifying that control banks are within the limits in the COLR per Specification 3.1.3.5.

c. When in MODE 2##, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits in the COLR per specification 3.1.3.5.

* See Special Test Exception 3.10.1

With $K_{eff} \geq 1.0$

With $K_{eff} < 1.0$

SURVEILLANCE REQUIREMENTS (Continued)

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the control banks at the maximum insertion limit in the COLR per Specification 3.1.3.5.

e. When in MODES 3 or 4, at least once per 24 hours by consideration of the following factors:

1. Reactor coolant system boron concentration,
2. Control rod position,
3. Reactor coolant system average temperature,
4. Fuel burnup based on gross thermal energy generation,
5. Xenon concentration, and
6. Samarium concentration.

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within ±1% Δk/k at least once per 31 Effective Full Power Days (EFPD). This comparison shall consider at least those factors stated in Specification 4.1.1.1.1.e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

SHUTDOWN MARGIN - T_{avg} ≤200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be ≥ 1.0% Δk/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN < 1.0% Δk/k, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be ≥ 1.0% Δk/k:

a. Within one hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable control rod(s).

b. At least once per 24 hours by consideration of the following factors:

   1. Reactor coolant system boron concentration,

   2. Control rod position,

   3. Reactor coolant system average temperature,

   4. Fuel burnup based on gross thermal energy generation,

   5. Xenon concentration, and

   6. Samarium concentration.

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MODERATOR TEMPERATURE COEFFICIENT

LIMITING CONDITION FOR OPERATION

3.1.1.4 The moderator temperature coefficient (MTC) shall be within the limits specified in the CORE OPERATING LIMITS REPORT (COLR). The maximum upper limit shall be less positive than or equal to 0 $\Delta k/k/°F$.

APPLICABILITY: Beginning of Cycle Life (BOL) Limit - MODES 1 and 2* only#
End of Cycle Life (EOL) Limit - MODES 1, 2 and 3 only#

ACTION:

a. With the MTC more positive than the BOL limit specified in the COLR, operations in MODES 1 and 2 may proceed provided:

   1. Control rod withdrawal limits are established and maintained sufficient to restore the MTC to less positive than the BOL limit specified in the COLR within 24 hours or be in HOT STANDBY within the next 6 hours. These withdrawal limits shall be in addition to the insertion limits in the COLR per Specification 3.1.3.5.

   2. The control rods are maintained within the withdrawal limits established above until a subsequent calculation verifies that the MTC has been restored to within its limit for the all rods withdrawn condition.

   3. A Special Report is prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days, describing the value of the measured MTC, the interim control rod withdrawal limits and the predicted average core burnup necessary for restoring the positive MTC to within its limit for the all rods withdrawn condition.

b. With the MTC more negative than the EOL limit specified in the COLR, be in HOT SHUTDOWN within 12 hours.

---

* With K_{eff} greater than or equal to 1.0

\# See Special Test Exception 3.10.3

SURVEILLANCE REQUIREMENTS

4.1.1.4 The MTC shall be determined to be within its limits during each fuel cycle as follows:

a. The MTC shall be measured and compared to the BOL limit specified in the COLR, prior to initial operation above 5% of RATED THERMAL POWER, after each fuel loading.

b. The MTC shall be measured at any THERMAL POWER and compared to the 300 ppm surveillance limit specified in the COLR (all rods withdrawn, RATED THERMAL POWER condition) within 7 EFPD after reaching an equilibrium boron concentration of 300 ppm. In the event this comparison indicates the MTC is more negative than the 300 ppm surveillance limit specified in the COLR, the MTC shall be remeasured, and compared to the EOL MTC limit specified in the COLR, at least once per 14 EFPD during the remainder of the fuel cycle.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.5 The Reactor Coolant System lowest operating loop temperature (T_{avg}) shall be $\geq$ 541°F.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{avg}) < 541°F, restore (T_{avg}) to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.5 The Reactor Coolant System temperature (T_{avg}) shall be determined to be $\geq$ 541°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{avg} is less than 551°F with the T_{avg} - T_{ref} Deviation Alarm not reset.

#With $K_{eff} \geq 1.0$.

3/4.1.2 BORATION SYSTEMS

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE:

a. A flow path from the boric acid tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System if the boric acid storage system is OPERABLE, per Specification 3.1.2.6a while in MODE 4, or per Specification 3.1.2.5a while in MODE 5 or 6, or

b. A flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System if the refueling water storage tank is OPERABLE per Specification 3.1.2.6b while in MODE 4, or per Specification 3.1.2.5b while in MODE 5 or 6.

APPLICABILITY: MODES 4, 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until at least one injection path is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. When the boric acid tank is a required water source, by verifying at least once per 7 days that:

(1) The flow path from the boric acid tank to the boric acid transfer pump, the boric acid transfer pump, and the recirculation path from the boric acid transfer pump to the boric acid tank is ≥ 63°F, and

(2) The flow path between the boric acid transfer pump recirculation line to the charging pump suction line is ≥ 50°F,

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 At least two of the following three boron injection flow paths shall be OPERABLE:

a. A flow path from the boric acid tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System.

b. Two flow paths from the refueling water storage tank via charging pumps to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F within the next 6 hours; restore at least two flow paths to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.2 Each of the above required flow paths shall be demonstrated OPERABLE:

a. By verifying at least once per 7 days that:

(1) The flow path from the boric acid tank to the boric acid transfer pump and from the recirculation line back to the boric acid tank is ≥ 63°F, and

(2) the flow path between the boric acid tank recirculation line to the charging pump suction line is ≥ 50°F,

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

SURVEILLANCE REQUIREMENTS (Continued)

c. * At least once per 18 months during shutdown by verifying that each automatic valve in the flow path actuates to its correct position on a safety injection test signal.

d. At least once per 18 months by verifying that the flow path required by specification 3.1.2.2.a delivers at least 33 gpm to the Reactor Coolant System.

* A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

CHARGING PUMP - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.3 At least one charging pump in the boron injection flow path required by Specification 3.1.2.1 shall be OPERABLE.#

APPLICABILITY: MODES 4, 5 and 6.

ACTION:

With no charging pump OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until one charging pump is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.3 No additional Surveillance Requirements other than those required by Specification 4.0.5.

A maximum of one centrifugal charging pump shall be OPERABLE while in MODE 4 when the temperature of one or more of the RCS cold legs is less than or equal to 312°F, MODE 5, or MODE 6 when the head is on the reactor vessel.

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% Δk/k at 200°F within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4 No additional Surveillance Requirements other than those required by Specification 4.0.5.

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BORATED WATER SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.5 As a minimum, one of the following borated water sources shall be OPERABLE:

a. A boric acid storage system with:

1. A minimum contained volume of 2,600 gallons,

2. Between 6,560 and 6,990 ppm of boron, and,

3. A minimum solution temperature of 63°F.

b. The refueling water storage tank with:

1. A minimum contained volume of 37,000 gallons,

2. A minimum boron concentration of 2300 ppm, and

3. A minimum solution temperature of 35°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until at least one borated water source is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.5 The above required borated water source shall be demonstrated OPERABLE:

a. For the boric acid storage system, when it is the source of borated water at least once per 7 days by:

1. Verifying the boron concentration of the water,

2. Verifying the water level of the tank, and

3. Verifying the boric acid storage tank solution temperature when it is the source of borated water.

b. For the refueling water storage tank by:

1. Verifying the boron concentration at least once per 7 days,

2. Verifying the borated water volume at least once per 7 days, and

3. Verifying the solution temperature at least once per 24 hours, when it is the source of borated water and the outside air temperature is less than 35°F.

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.6 As a minimum, the following borated water source(s) shall be OPERABLE as required by specifications 3.1.2.1 and 3.1.2.2:

a. A boric acid storage system with:

1. A contained volume of borated water in accordance with figure 3.1.2,

2. A boron concentration in accordance with figure 3.1-2, and

3. A minimum solution temperature of 63°F.

b. The refueling water storage tank with:

1. A contained volume of between 364,500 and 400,000 gallons of water,

2. A boron concentration of between 2,300 and 2,500 ppm, and

3. A minimum solution temperature of 35°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With the boric acid storage system inoperable and being used as one of the above required boration water systems, restore the storage system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta K/k at 200°F; restore the boric acid storage system to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 Each borated water source shall be demonstrated OPERABLE:

SURVEILLANCE REQUIREMENTS (Continued)

a. For the boric acid storage system, when it is the source of borated water at least once per 7 days by:

1. Verifying the boron concentration in each water source,

2. Verifying the water level of each water source, and

3. Verifying the boric acid storage system solution temperature.

b. For the refueling water storage tank by:

1. Verifying the boron concentration at least once per 7 days,

2. Verifying the borated water volume at least once per 7 days, and

3. Verifying the solution temperature at least once per 24 hours when the outside air temperature is less than 35°F.

BORIC ACID TANK CONTENTS

BASED ON RWST CONCENTRATION

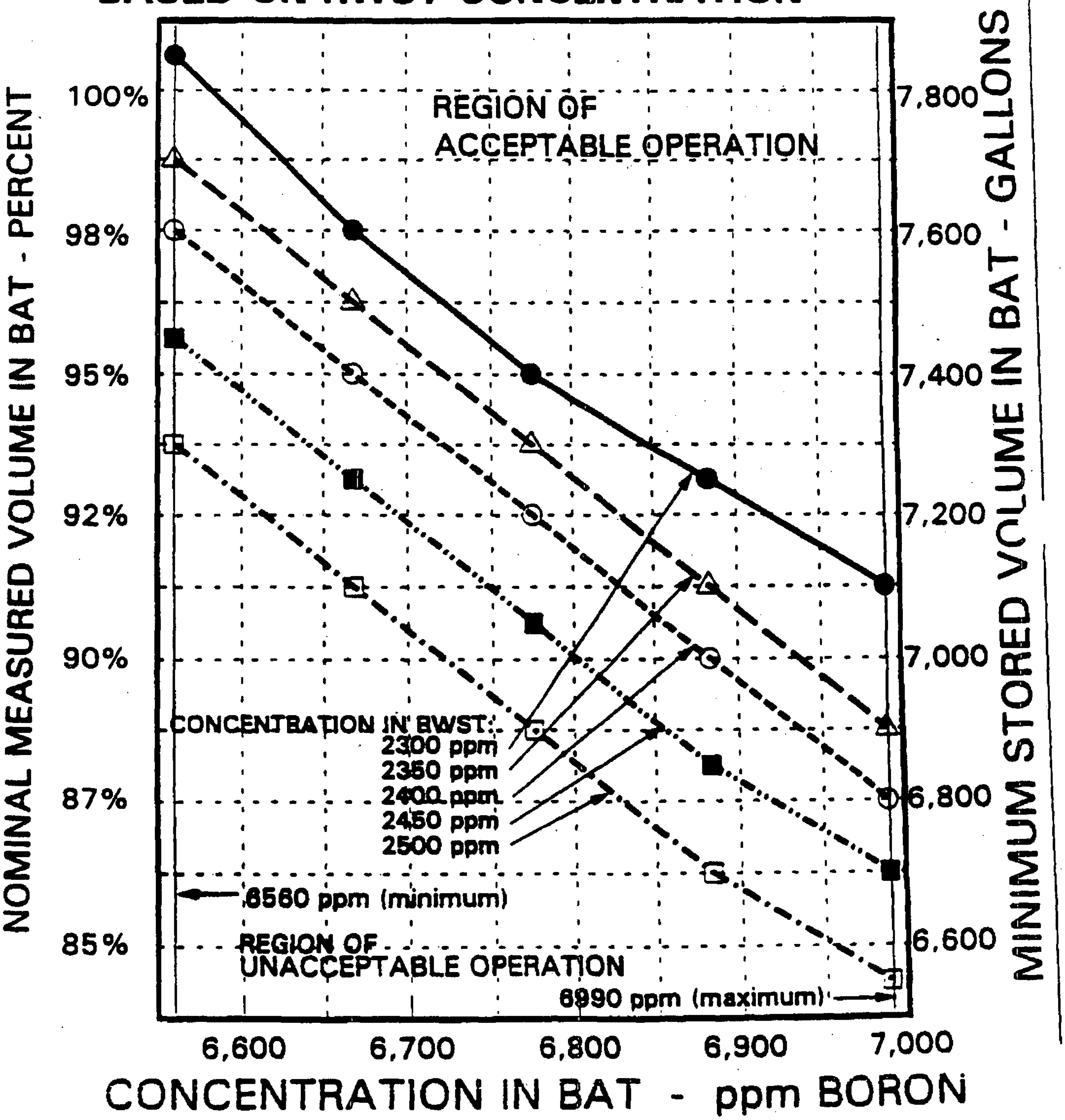

Figure 3.1-2

REACTIVITY CONTROL SYSTEMS

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

GROUP HEIGHT

LIMITING CONDITION FOR OPERATION

3.1.3.1 All full length (shutdown and control) rods, shall be OPERABLE and positioned within ± 18 steps(indicated position) when reactor power is ≤ 85 %, RATED THERMAL POWER, or ± 12 steps (indicated position) when reactor power is > 85% RATED THERMAL POWER, of their group step counter demand position within one hour after rod motion.

APPLICABILITY: MODES 1* and 2*

ACTION:

a. With one or more full length rods inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in HOT STANDBY within 6 hours.

b. With more than one full length rod inoperable or mis-aligned from the group step counter demand position by more than ± 18 steps(indicated position) at ≤ 85 % RATED THERMAL POWER or ± 12 steps (indicated position) at > 85% RATED THERMAL POWER, be in HOT STANDBY within 6 hours.

c. With one full length rod inoperable due to causes other than addressed by ACTION a, above, or mis-aligned from its group step counter demand position by more than ± 18 steps(indicated position) at ≤ 85 % RATED THERMAL POWER or ± 12 steps (indicated position) at > 85% RATED THERMAL POWER, POWER OPERATION may continue provided that within one hour either:

   1. The rod is restored to OPERABLE status within the above alignment requirements, or

   2. The remainder of the rods in the bank with the inoperable rod are aligned to within ± 18 steps(indicated position) at ≤ 85 % RATED THERMAL POWER or ± 12 steps (indicated position) at > 85% RATED THERMAL POWER of the inoperable rod while maintaining the rod sequence and insertion limits in the COLR per specification 3.1.3.5. The THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.5 during subsequent operation, or

   3. The rod is declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. POWER OPERATION may then continue provided that:

* See Special Test Exceptions 3.10.2 and 3.10.3.

a) A reevaluation of each accident analysis of table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions.

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

c) A core power distribution measurement is obtained and F_Q (Z). $F^N_{\Delta H}$ are verified to be within their limits within 72 hours.

d) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within one hour and within the next 4 hours the high neutron flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER. THERMAL POWER shall be maintained less than or equal to 75% of RATED THERMAL POWER until compliance with ACTIONS 3.1.3.1.c.3.a and 3.1.3.1.c.3.c above are demonstrated.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full length rod shall be determined to be within the limits established in the limiting condition for operation at least once per 12 hours (allowing for one hour thermal soak after rod motion) except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.*

4.1.3.1.2 Each full length rod not fully inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction at least once per 31 days.

* During Cycle 14, the position of Rod 1SB2 will be determined indirectly by the movable incore detectors within 8 hours following its movement until the repair of the indication system for this rod. During reactor startup, the fully withdrawn position of Rod 1SB2 will be determined by current traces and subsequently verified by the movable incore detectors prior to entry into Mode 1.

TABLE 3.1-1

ACCIDENT ANALYSES REQUIRING REEVALUATION IN THE EVENT OF AN INOPERABLE FULL LENGTH ROD

Rod Cluster Control Assembly Insertion Characteristics

Rod Cluster Control Assembly Mis-alignment

Loss Of Reactor Coolant From Ruptured Pipes Or From Cracks In Large Pipes Which Actuates The Emergency Core Cooling System

Single Rod Cluster Control Assembly Withdrawal At Full Power

Major Reactor Coolant System Pipe Ruptures (Loss Of Coolant Accident)

Major Secondary System Pipe Rupture

Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

POSITION INDICATION SYSTEMS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2.1 The shutdown and control rod position indication systems shall be OPERABLE and capable of determining the actual and demanded rod positions as follows:

a. Analog rod position indicators, within one hour after rod motion (allowance for thermal soak);

All Shutdnwn Banks: ±18 steps at ≤ 85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Rank A: ±18 steps at ≤ 85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Bank B: ±18 steps at ≤ 85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 160-228 steps.

Control Bank C and D: ±18 steps at ≤ 85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-228 steps.

b. Group demand counters; ± 2 steps of the pulsed output of the Slave Cycler Circuit over the withdrawal range of 0-228 steps.

APPLICABILITY: MODES 1 and 2.
ACTION:

a. With a maximum of one analog rod position indicator per bank inoperable either:

1. Determine the position of the non-indicating rod(s) indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) at least once per 8 hours* and within one hour after any motion of the non-indicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, or
2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

* During Cycle 14, the position of Rod 1SB2 will be determined indirectly by the movable incore detectors within 8 hours following its movement until the repair of the indication system for this rod. During reactor startup, the fully withdrawn position will be determined by current traces and subsequently verified by the movable incore detectors prior to entry into Mode 1.

b. With two or more analog rod position indicators per bank inoperable, within one hour restore the inoperable rod position indicator(s) to OPERABLE status or be in HOT STANDBY within the next 6 hours. A maximum of one rod position indicator per bank may remain inoperable following the hour, with Action (a) above being applicable from the original entry time into the LCO.

c. With a maximum of one group demand position indicator per bank inoperable either:

1. Verify that all analog rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 18 steps when reactor power is ≤ 85% RATED THERMAL POWER or if reactor power is > 85% RATED THERMAL POWER, 12 steps of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2.1.1 Each analog rod position indicator shall be determined to be OPERABLE by verifying that the demand position indication system and the rod position indication system agree within 18 steps when reactor power is ≤ 85% RATED THERMAL POWER or if reactor power is > 85% RATED THERMAL POWER, 12 steps (allowing for one hour thermal soak after rod motion) at least once per 12 hours except during time intervals when the Rod Position Deviation Monitor is inoperable, then compare the demand position indication system and the rod position indication system at least once per 4 hours.

4.1.3.2.1.2 Each of the above required rod position indicator(s) shall be determined to be OPERABLE by performance of a CHANNEL calibration at least once per 18 months.

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REACTIVITY CONTROL SYSTEMS

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.3 The individual full length (shutdown and control) rod drop time from 228 steps withdrawn shall be ≤ 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} ≥ 541°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 & 2.

ACTION:

a. With the drop time of any full length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

b. With the rod drop times within limits but determined with 3 reactor coolant pumps operating, operation may proceed provided THERMAL POWER is restricted to ≤71% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.1.3.3 The rod drop time of full length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the control rod drive system which could affect the drop time of those specific rods, and

c. At least once per 18 months.

SHUTDOWN ROD INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.4 All shutdown rods shall be FULLY WITHDRAWN.

APPLICABILITY: MODES 1*, and 2*#@

ACTION:

With a maximum of one shutdown rod not FULLY WITHDRAWN, except for surveillance testing pursuant to Specification 4.1.3.1.2, within one hour either:

a. FULLY WITHDRAW the rod, or,

b. Declare the rod to be inoperable and apply Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.4 Each shutdown rod shall be determined to be FULLY WITHDRAWN by use of the group demand counters, and verified by the analog rod position indicators**,***:

a. Within 15 minutes prior to withdrawal of any rods in control banks A, B, C, or D during an approach to reactor criticality, and

b. At least once per 12 hours thereafter.

* See Special Test Exceptions 3.10.2 and 3.10.3
**For power levels below 50% one hour thermal "soak time" is permitted. During this soak time, the absolute value of rod motion is limited to six steps.
*** During Cycle 14, the position of Rod 1SB2 will be determined indirectly by the movable incore detectors within 8 hours following its movement until the repair of the indication system for this rod. During reactor startup, the fully withdrawn position of Rod 1SB2 will be determined by current traces and subsequently verified by the movable incore detectors prior to entry into Mode 1.
# With Keff greater than or equal to 1.0
@ Surveillance 4.1.3.4.a is applicable prior to withdrawing control banks in preparation for startup (Mode 2).

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.5 The control banks shall be limited in physical insertion as specified in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODES 1*, and 2*#

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification 4.1.3.1.2, either:

a. Restore the control banks to within the limits within two hours, or

b. Reduce THERMAL POWER within two hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the insertion limits specified in the COLR, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.5 The position of each control bank shall be determined to be within the insertion limits at least once per 12 hours by use of the group demand counters and verified by the analog rod position indicators** except during time intervals when the Rod Insertion Limit Monitor is inoperable, then verify the individual rod positions at least once per 4 hours**.

* See Special Test Exceptions 3.10.2 and 3.10.3

** For power levels below 50% one hour thermal "soak time" is permitted. During this soak time, the absolute value of rod motion is limited to six steps.

\# With K_{eff} greater than or equal to 1.0

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AXIAL FLUX DIFFERENCE (AFD)

LIMITING CONDITION FOR OPERATION

3.2.1 The indicated AXIAL FLUX DIFFERENCE (AFD) shall be maintained within the target band about the target flux difference as specified in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODE 1 ABOVE 50% RATED THERMAL POWER*

ACTION:

a. With the indicated AXIAL FLUX DIFFERENCE outside of the limits specified in the COLR and with THERMAL POWER:

   1. Above 90% of RATED THERMAL POWER, within 15 minutes:

      a) Either restore the indicated AFD to within the target band limits, or

      b) Reduce THERMAL POWER to less than 90% of RATED THERMAL POWER.

   2. Between 50% and 90% of RATED THERMAL POWER:

      a) POWER OPERATION may continue provided:

         1) The indicated AFD has not been outside of the limits specified in the COLR for more than 1 hour penalty deviation cumulative during the previous 24 hours, and

         2) The indicated AFD is within the limits specified in the COLR. Otherwise, reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 30 minutes and reduce the Power Range Neutron Flux-High Trip Setpoints to ≤ 55% of RATED THERMAL POWER within the next 4 hours.

      b) Surveillance testing of the Power Range Neutron Flux Channels may be performed pursuant to Specification 4.3.1.1.1 provided the indicated AFD is maintained within the limits specified in the COLR. A total of 16 hours operation may be accumulated with the AFD outside of the target band during this testing without penalty deviation.

---

*See Special Test Exception 3.10.2

LIMITING CONDITION FOR OPERATION (Continued)

b. THERMAL POWER shall not be increased above 90% of RATED THERMAL POWER unless the indicated AFD is within the limits specified in the COLR and ACTION a.2.a)1), above has been satisfied.

c. THERMAL POWER shall not be increased above 50% of RATED THERMAL POWER unless the indicated AFD has not been outside of the limits specified in the COLR for more than 1 hour penalty deviation cumulative during the previous 24 hours.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AXIAL FLUX DIFFERENCE shall be determined to be within its limits during POWER OPERATION above 15% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1. At least once per 7 days when the AFD Monitor Alarm is OPERABLE, and

2. At least once per hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status.

b. Monitoring and logging the indicated AXIAL FLUX DIFFERENCE for each OPERABLE excore channel at least once per hour for the first 24 hours and at least once per 30 minutes thereafter, when the AXIAL FLUX DIFFERENCE Monitor Alarm is inoperable. The logged values of the indicated AXIAL FLUX DIFFERENCE shall be assumed to exist during the interval preceding each logging.

4.2.1.2 The indicated AFD shall be considered outside of its limits when at least 2 of 4 or 2 of 3 OPERABLE excore channels are indicating the AFD to be outside of the target band. Penalty deviation outside of the target band shall be accumulated on a time basis of:

a. One minute penalty deviation for each one minute of POWER OPERATION outside of the limits at THERMAL POWER levels equal to or above 50% of RATED THERMAL POWER, and

b. One-half minute penalty deviation for each one minute of POWER OPERATION outside of the limits at THERMAL POWER levels below 50% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.1.3 The target flux difference of each OPERABLE excore channel shall be determined by measurement at least once per 92 Effective Full Power Days. The provisions of Specification 4.0.4 are not applicable.

4.2.1.4 The target flux difference shall be updated at least once per 31 Effective Full Power Days by either determining the target flux difference pursuant to 4.2.1.3 above or by linear interpolation between the most recently measured value and 0 percent at the end of the cycle life. The provisions of Specification 4.0.4 are not applicable.

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HEAT FLUX HOT CHANNEL FACTOR-$F_Q(Z)$

LIMITING CONDITION FOR OPERATION

3.2.2 $F_Q(z)$ shall be limited by the following relationships:

$$F_Q(z) \leq \frac{F^{RTP}_Q}{P} * K(z) \text{ for } P > 0.5, \text{ and}$$

$$F_Q(z) \leq \frac{F^{RTP}_Q}{0.5} * K(z) \text{ for } P \leq 0.5,$$

Where: F^{RTP}_Q = the F_Q limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT (COLR),

$$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}, \text{ and}$$

K(z) = the normalized $F_Q(z)$ as a function of core height as specified in the COLR.

APPLICABILITY: MODE 1

ACTION:

With $F_Q(z)$ exceeding its limit:

a. Reduce THERMAL POWER at least 1% for each 1% $F_Q(Z)$ exceeds the limit within 15 minutes and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours; POWER OPERATION may proceed for up to a total of 72 hours; subsequent POWER OPERATION may proceed provided the Overpower ΔT Trip Setpoints have been reduced at least 1% for each 1% $F_Q(Z)$ exceeds the limit. The Overpower ΔT Trip Setpoint reduction shall be performed with the reactor in at least HOT STANDBY.

b. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER above the reduced limit required by a. above; THERMAL POWER may then be increased provided $F_Q(Z)$ is demonstrated through a core power distribution measurement to be within its limit.

4.2.2.1 The provisions of Specification 4.0.4 are not applicable.

4.2.2.2 F_{xy} shall be evaluated to determine if $F_Q(Z)$ is within its limit by:

a. Using the movable incore detectors to obtain a power distribution map:

1. When THERMAL POWER is ≤ 25%, but > 5% of RATED THERMAL POWER, or
2. When the Power Distribution Monitoring System (PDMS) is inoperable;

and increasing the Measured $F_Q(Z)$ by the applicable manufacturing and measurement uncertainties as specified in the COLR.

b. Using the PDMS or the moveable incore detectors when THERMAL POWER is > 25% of RATED THERMAL POWER, and increasing the measured $F_Q(Z)$ by the applicable manufacturing and measurement uncertainties as specified in the COLR.

c. Comparing the F_{xy} computed (F_{xy}^C) obtained in b, above to:

1. The F_{xy} limits for RATED THERMAL POWER (F_{xy}^{RTP}) for the appropriate measured core planes given in e and f below, and

2. The relationship:

$$F_{xy}^L = F_{xy}^{RTP} [1+PF_{xy} (1-P)]$$

where F_{xy}^L is the limit for fractional THERMAL POWER operation expressed as a function of F_{xy}^{RTP}, PF_{xy} is the power factor multiplier for F_{xy} in the COLR, and P is the fraction of RATED THERMAL POWER at which F_{xy} was measured.

d. Remeasuring F_{xy} according to the following schedule:

1. When F_{xy}^C is greater than the F_{xy}^{RTP} limit for the appropriate measured core plane but less than the F_{xy}^L relationship, additional core power distribution measurements shall be taken and F_{xy}^C compared to F_{xy}^{RTP} and F_{xy}^L:

a) Either within 24 hours after exceeding by 20% of RATED THERMAL POWER or greater, the THERMAL POWER at which F_{xy}^C was last determined, or

SURVEILLANCE REQUIREMENTS (Continued)

b) At least once per 31 EFPD, whichever occurs first.

2. When the F^C_{xy} is less than or equal to the F^{RTP}_{xy} limit for the appropriate measured core plane, additional core power distribution measurements shall be taken and F^C_{xy} compared to F^{RTP}_{xy} and F^L_{xy} at least once per 31 EFPD.

e. The F_{xy} limit for Rated Thermal Power (F^{RTP}_{xy}) shall be provided for all core planes containing bank "D" control rods and all unrodded core planes in the COLR per specification 6.9.1.9.

f. The F_{xy} limits of e, above, are not applicable in the following core plane regions as measured in percent of core height from the bottom of the fuel:

1. Lower core region from 0 to 15% inclusive.
2. Upper core region from 85 to 100% inclusive.
3. Grid plane regions at 17.8 ± 2%, 32.1 ±2%, 46.4 ±2%, 60.6 ±2%, and 74.9 ±2% inclusive.
4. Core plane regions within ±2% of core height (±2.88 inches) about the bank demand position of the bank "D" control rods.

g. Evaluating the effects of F_{xy} on $F_Q(Z)$ to determine if $F_Q(Z)$ is within its limit whenever F^C_{xy} exceeds F^L_{xy}.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.2.3 When $F_Q(Z)$ is measured pursuant to specification 4.10.2.2, an overall measured $F_Q(Z)$ shall be obtained from a core power distribution measurement and increased by the applicable manufacturing and measurement uncertainties as specified in the COLR.

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POWER DISTRIBUTION LIMITS

NUCLEAR ENTHALPY HOT CHANNEL FACTOR - $F^N_{\Delta H}$

LIMITING CONDITION FOR OPERATION

3.2.3 $F^N_{\Delta H}$ shall be limited by the following relationship:

$$F^N_{\Delta H} = F^{RTP}_{\Delta H} [1.0 + PF_{\Delta H} (1.0 - P)]$$

Where: $F^{RTP}_{\Delta H}$ is the limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT (COLR).

$PF_{\Delta H}$ is the Power Factor Multiplier for $F^N_{\Delta H}$ specified in the COLR, and

P is $\dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

APPLICABILITY: MODE 1

ACTION:

With $F^N_{\Delta H}$ exceeding its limit:

a. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to ≤ 55% of RATED THERMAL POWER within the next 4 hours.

b. Demonstrate thru a core power distribution measurement that $F^N_{\Delta H}$ is within its limit within 24 hours after exceeding the limit or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours, and

c. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER above the reduced limit required by a. or b. above; subsequent POWER OPERATION may proceed provided that $F^N_{\Delta H}$ is demonstrated through a core power distribution measurement to be within its limit at a nominal 50% of RATED THERMAL POWER prior to exceeding this THERMAL POWER, at a nominal 75% of RATED THERMAL POWER prior to exceeding this THERMAL power and within 24 hours after attaining 95% or greater RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.3.1 $F^N_{\Delta H}$ shall be determined to be within its limit by obtaining a core power distribution measurement:

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. At least once per 31 Effective Full Power Days.

c. The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 The measured $F^N_{\Delta H}$ of 4.2.3.1 above, shall be increased by the applicable $F^N_{\Delta H}$ uncertainties specified in the COLR.

QUADRANT POWER TILT RATIO

LIMITING CONDITION FOR OPERATION

3.2.4 THE QUADRANT POWER TILT RATIO shall not exceed 1.02.

APPLICABILITY: MODE 1 ABOVE 50% OF RATED THERMAL POWER*

ACTION:

a. With the QUADRANT POWER TILT RATIO determined to exceed 1.02 but $\leq$ 1.09:

   1. Within 2 hours:

      a) Either reduce the QUADRANT POWER TILT RATIO to within its limit, or

      b) Reduce THERMAL POWER at least 3% from RATED THERMAL POWER for each 1% of indicated QUADRANT POWER TILT RATIO in excess of 1.0 and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours.

   2. Verify that the QUADRANT POWER TILT RATIO is within its limit within 24 hours after exceeding the limit or reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within the next 2 hours and reduce the Power Range Neutron Flux-High Trip setpoints to $\leq$ 55% of RATED THERMAL POWER within the next 4 hours.

   3. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL power may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified acceptable at 95% or greater RATED THERMAL POWER.

b. With the QUADRANT POWER TILT RATIO determined to exceed 1.09 due to misalignment of either a shutdown or control rod:

   1. Reduce THERMAL POWER at least 3% from RATED THERMAL POWER for each 1% of indicated QUADRANT POWER TILT RATIO in excess of 1.0, within 30 minutes.

   2. Verify that the QUADRANT POWER TILT RATIO is within its limit within 2 hours after exceeding the limit or

*See Special Test Exception 3.10.2.

reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within the next 2 hours and reduce the Power Range Neutron Flux-High trip Setpoints to ≤ 55% of RATED THERMAL POWER within the next 4 hours.

3. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL POWER may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified acceptable at 95% or greater RATED THERMAL POWER.

c. With the QUADRANT POWER TILT RATIO determined to exceed 1.09 due to causes other than the misalignment of either a shutdown or control rod:

1. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to ≤ 55% of RATED THERMAL POWER within the next 4 hours.

2. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL POWER may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified at 95% or greater RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.4 The QUADRANT POWER TILT RATIO shall be determined to be within the limit above 50% of RATED THERMAL POWER by:

a. Calculating the ratio at least once per 7 days when the alarm is OPERABLE.

b. Calculating the ratio at least once per 12 hours during steady state operation when the alarm is inoperable.

c. Obtaining a core power distribution measurement to determine the QUADRANT POWER TILT RATIO at least once per 12 hours when one Power Range Channel is inoperable and THERMAL POWER is > 75 percent of RATED THERMAL POWER.

POWER DISTRIBUTION LIMITS

DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the limits shown on Table 3.2-1:

a. Reactor Coolant System T_{avg}.

b. Pressurizer Pressure

c. Reactor Coolant System Total Flow Rate

APPLICABILITY: MODE 1

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters of Table 3.2-1 shall be verified to be within their limits at least once per 12 hours.

4.2.5.2 The Reactor Coolant System total flow rate shall be determined to be within the limits of Table 3.2-1 by performing a precision heat balance within 24 hours after achieving steady state conditions ≥90% RATED THERMAL POWER at least once per 18 months. The provisions of Specification 4.0.4 are not applicable.

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS
	4 Loops In Operation
Reactor Coolant System T_{avg}	≤ 582.9°F
Pressurizer Pressure	≥ 2200 psia*
Reactor Coolant System Flow	≥ 341,000 gpm#

* Limit not applicable during either THERMAL POWER ramp increase in excess of 5% RATED THERMAL POWER per minute or a THERMAL POWER step increase in excess of 10% RATED THERMAL POWER.

\# Includes a 2.4% flow measurement uncertainty plus a 0.1% measurement uncertainty due to feedwater venturi fouling.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1.1 As a minimum, the reactor trip system instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each reactor trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the MODES and at the frequencies shown in Table 4.3-1.

4.3.1.1.2 The logic for the interlocks shall be demonstrated OPERABLE prior to each reactor startup unless performed during the preceding 92 days. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.1.1.3 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be verified to be within its limit at least once per 18 months. Neutron detectors are exempt from response time testing. Each verification shall include at least one logic train such that both logic trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. of Channels" column of Table 3.3-1.

TABLE 3.3-1
REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1,2 and *	12
2. Power Range, Neutron Flux	4	2	3	1,2, and 3*	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1,2	2
4. Deleted					
5. Intermediate Range, Neutron Flux	2	1	2	1,2 and *	3
6. Source Range, Neutron Flux					
A. Startup	2	1	2	2## and *	4
B. Shutdown	2	0	1	3,4, and 5	5
7. Overtemperature ΔT	4	2	3	1,2	6
8. Overpower ΔT	4	2	3	1,2	6
9. Pressurizer Pressure-Low	4	2	3	1,2	6
10. Pressurizer Pressure--High	4	2	3	1,2	6

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT		TOTAL NUMBER OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11.	Pressurizer Water Level--High	3	2	2	1, 2	6
12.	Loss of Flow - Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	6
13.	Loss of Flow - Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop in each operating loop	1	6
14.	Steam Generator Water Level--Low-Low	3/loop	2/loop in any operating loops	2/loop in each operating loop	1, 2	6
15.	Deleted					
16.	Undervoltage-Reactor Coolant Pumps	4-1/bus	1/2 twice	3	1	6
17.	Underfrequency-Reactor Coolant Pumps	4-1/bus	1/2 twice	3	1	6

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
a. Low Autostop Oil Pressure	3	2	2	1	6
b. Turbine Stop Valve Closure	4	4	3	1	6
19. Safety Injection Input from ESF	2	1	2	1,2	10
20. Reactor Coolant Pump Breaker Position Trip (above P-7)	1/breaker	2	1/breaker per operating loop	1	11
21. Reactor Trip Breakers	2	1	2	1, 2 3*,4*,5*	1###,14 13
22. Automatic Trip Logic	2	1	2	1, 2 3*,4*,5*	10 13

TABLE 3.3-1 (Continued)

TABLE NOTATION

* With the reactor trip system breakers in the closed position and the control rod drive system capable of rod withdrawal.

High voltage to detector may be de-energized above P-6.

If ACTION Statement 1 is entered as a result of Reactor Trip Breaker (RTB) or Reactor Trip Bypass Breakers (RTBB) maintenance testing results exceeding the following acceptance criteria, NRC reporting shall be made within 30 days in accordance with Specification 6.9.2:

1. A RTB or RTBB trip failure during any surveillance test with less than or equal to 300 grams of weight added to the breaker trip bar.

2. A RTB or RTBB time response failure that results in the overall reactor trip system time response exceeding the Technical Specification limit.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, be in HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1.1 provided the other channel is OPERABLE.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

c. Either, THERMAL POWER is restricted to ≤ 75% of RATED THERMAL POWER and the Power Range, Neutron Flux trip setpoint is reduced to ≤ 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours.

TABLE 3.3-1 (Continued)

ACTION 3 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below P-6, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above P-6 but below 5% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 5% of RATED THERMAL POWER.

c. Above 5% of RATED THERMAL POWER, POWER OPERATION may continue.

ACTION 4 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below P-6, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above P-6, operation may continue.

ACTION 5 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

ACTION 7 - NOT USED

ACTION 8 - NOT USED

ACTION 9 - NOT USED

TABLE 3.3-1 (Continued)

ACTION 10 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY in the next 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1.1, provided the other channel is OPERABLE.

ACTION 11 - With less than the Minimum Number of Channels OPERABLE, operation may continue provided the inoperable channel is placed in the tripped condition within 6 hours.

ACTION 12 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and/or open the reactor trip breakers.

ACTION 13 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

ACTION 14 - With one of the diverse trip features (Undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and be in at least HOT STANDBY within 6 hours. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status.

REACTOR TRIP SYSTEM INTERLOCKS

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-6	With 2 of 2 Intermediate Range Neutron Flux Channels < $6x10^{-11}$ amps.	P-6 prevents or defeats the manual block of source range reactor trip.
P-7	With 2 of 4 Power Range Neutron Flux Channels ≥ 11% of RATED THERMAL POWER or 1 of 2 Turbine steam line input pressure channels ≥ a pressure equivalent to 11% of RATED THERMAL POWER.	P-7 prevents or defeats the automatic block of reactor trip on: Low flow in more than one primary coolant loop, reactor coolant pump undervoltage and under-frequency, pressurizer low pressure, pressurizer high level, and the opening of more than one reactor coolant pump breaker.

TABLE 3.3-1 (Continued)

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-8	With 2 of 4 Power Range Neutron Flux channels ≥ 36% of RATED THERMAL POWER.	P-8 prevents or defeats the automatic block of reactor trip on low coolant flow in a single loop.
P-9	With 2 of 4 Power Range neutron flux channels ≥ 50% RATED THERMAL POWER.	P-9 prevents or defeats the automatic block of reactor trip on turbine trip.
P-10	With 3 of 4 Power range neutron flux channels < 9% of RATED THERMAL POWER.	P-10 prevents or defeats the manual block of: Power range low setpoint reactor trip, Intermediate range reactor trip, and intermediate range rod stops. Provides input to P-7.

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TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. Manual Reactor Trip Switch	N.A.	N.A.	$R^{(9)}$	1, 2, and *
2. Power Range, Neutron Flux	S	$D^{(2)}$, $M^{(3)}$ and $Q^{(6)}$	Q	1, 2, and 3*
3. Power Range, Neutron Flux, High Positive Rate	N.A.	$R^{(6)}$	Q	1, 2
4. Deleted				
5. Intermediate Range, Neutron Flux	S	$R^{(6)}$	$S/U^{(1)}$	1, 2 and *
6. Source Range, Neutron Flux	$S^{(7)}$	$R^{(6)}$	Q and $S/U^{(1)}$	2, 3, 4, 5 and *
7. Overtemperature ΔT	S	R	Q	1, 2
8. Overpower ΔT	S	R	Q	1, 2
9. Pressurizer Pressure--Low	S	R	Q	1, 2
10. Pressurizer Pressure--High	S	R	Q	1, 2
11. Pressurizer Water Level--High	S	R	Q	1, 2
12. Loss of Flow - Single Loop	S	R	Q	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
13. Loss of Flow Two Loops	S	R	N.A.	1
14. Steam Generator Water Level--Low-Low	S	R	Q	1, 2
15. DELETED				
16. Undervoltage - Reactor Coolant Pumps	N.A.	R	Q	1
17. Underfrequency - Reactor Coolant Pumps	N.A.	R	Q	1
18. Turbine Trip				
a. Low Autostop Oil Pressure	N.A.	N.A.	S/U(1)	1, 2
b. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1, 2
19. Safety Injection Input from ESF	N.A.	N.A.	M(4)(5)	1, 2
20. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	R	1
21. Reactor Trip Breaker	N.A.	N.A.	M(5)(11)(13) and R(14)	1, 2 and *
22. Automatic Trip Logic	N.A.	N.A.	M(5)	1, 2 and *

TABLE 4.3-1 (Continued)

NOTATION

* With the reactor trip system breakers closed and the control rod drive system capable of rod withdrawal.

(1) - If not performed in previous 31 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER.

(3) - Compare incore to excore axial offset above 15% of RATED THERMAL POWER. Recalibrate if absolute difference ≥ 3 percent.

(4) - Manual SSPS functional input check every 18 months. **

(5) - Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(6) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(7) - Below P-6 (Block of Source Range Reactor Trip) setpoint.

(8) - Deleted

(9) - The CHANNEL FUNCTIONAL TEST shall independently verify the OPERABILITY of the Undervoltage and Shunt Trip mechanism for the Manual Reactor Trip Function.

The Test shall also verify OPERABILITY of the Bypass Breaker Trip circuits.

(10) - DELETED

(11) - The CHANNEL FUNCTIONAL TEST shall independently verify the OPERABILITY of the Reactor Trip Breaker Undervoltage and Shunt Trip mechanisms.

(12) - DELETED

** A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

TABLE 4.3-1 (Continued)

NOTATION

(13) - Verify operation of Bypass Breakers Shunt Trip function from local pushbutton while breaker is in the test position prior to placing breaker in service.

(14) - Perform a functional test of the Bypass Breakers U.V. Attachment via the SSPS.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2.1 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an ESFAS instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint value.

b. With an ESFAS instrumentation channel inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each ESFAS instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the MODES and at the frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the interlocks shall be demonstrated OPERABLE during the automatic actuation logic test. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be verified to be within the limit at least once per 18 months. Each verification shall include at least one logic train such that both logic trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" Column of Table 3.3-3. The provisions of Specification 4.0.4 are not applicable to MSIV closure time testing. The provisions of Specification 4.0.4 are not applicable to the turbine driven auxiliary feedwater pump provided the surveillance is performed within 24 hours after the secondary steam generator pressure is greater than 680 psig.

TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION					
a. Manual Initiation	2	1	2	1,2,3,4	18
b. Automatic Actuation Logic	2	1	2	1,2,3,4	13
c. Containment Pressure-High	3	2	2	1,2,3	19
d. Pressurizer Pressure-Low	3	2	2	1,2,3#	19
e. Differential Pressure Between Steam Lines - High	3/steam line	2/steam line any steam line	2/steam line	1,2,3##	19
f. Steam Flow in Two Steam Lines-High	2/steam line	1/steam line any 2 steam lines	1/steam line	1,2,3##	19
COINCIDENT WITH EITHER					
Tavg --Low-Low	1 Tavg/loop	1 Tavg in any 2 loops	1 Tavg in any 3 loops	1,2,3##	19
OR, COINCIDENT WITH					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any 2 loops	1 pressure any 3 loops	1,2,3##	19

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TABLE 3.3-3 (Continued)
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
2. CONTAINMENT SPRAY					
a. Manual	2 sets of 2	1 set of 2	2 sets of 2	1,2,3,4	18
b. Automatic Actuation Logic	2	1	2	1,2,3,4	13
c. Containment Pressure--High-High	4	2	3	1,2,3	16
3. CONTAINMENT ISOLATION					
a. Phase "A" Isolation					
1) Manual	2	1	2	1,2,3,4	18
2) From Safety Injection Automatic Actuation Logic	2	1	2	1,2,3,4	13

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
b. Phase "B" Isolation					
1) Manual	2 sets of 2	1 set of 2	2 sets of 2	1,2,3,4	18
2) Automatic Actuation Logic	2	1	2	1,2,3,4	13
3) Containment Pressure--High-High	4	2	3	1,2,3	16
c. Containment Ventilation Isolation					
1) Manual	2	1	2	1,2,3,4	17
2) Automatic Actuation Logic	2	1	2	1,2,3,4	13
3) Containment Atmosphere Gaseous Radioactivity-High		per table 3.3-6			

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. STEAM LINE ISOLATION					
a. Manual	2/steam line	1/steam line	1/operating steam line	1,2,3	23
b. Automatic Actuation Logic	2***	1	2	1,2,3	20
c. Containment Pressure--High-High	4	2	3	1,2,3	16
d. Steam Flow in Two Steam Lines--High	2/steam line	1/steam line any 2 steam lines	1/steam line	1,2,3##	19
COINCIDENT WITH EITHER					
Tavg--Low-Low	1 Tavg/loop	1 Tavg in any 2 loops	1 Tavg in any 3 loops	1,2,3##	19
OR, COINCIDENT WITH					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any 2 loops	1 pressure any 3 loops	1,2,3##	19

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
5. TURBINE TRIP & FEEDWATER ISOLATION					
a. Steam Generator Water level-- High-High	3/loop	2/loop in any operating loop	2/loop in each operating loop	1,2,3	19
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC)	3	2	3	1,2,3,4	13
7. UNDERVOLTAGE, VITAL BUS					
a. Loss of Voltage	1/bus	2	3	1,2,3	14
b. Sustained Degraded Voltage	3/bus	2/bus	3/bus	1,2,3	14

TABLE 3.3-3 (Continued)
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
8. AUXILIARY FEEDWATER					
a. Automatic Actuation Logic **	2	1	2	1,2,3	20
b. NOT USED					
c. Steam Generator Water Level--Low-Low					
i. Start Motor Driven Pumps	3/stm. gen.	2/stm. gen. any stm.gen.	2/stm.gen.	1,2,3	19
ii.Start Turbine Driven Pumps	3/stm. gen.	2/stm. gen. any 2 stm.gen.	2/stm.gen.	1,2,3	19
d. Undervoltage - RCP Start Turbine - Driven Pump	4-1/bus	1/2 x 2	3	1,2	19
e. S.I. Start Motor-Driven Pumps	See 1 above (All S.I. initiating functions and requirements)				
f. Trip of Main Feedwater Pumps Start Motor Driven Pumps	2/pump	1/pump	1/pump	1,2	21
g. Station Blackout	See 6 and 7 above (SEC and U/V Vital Bus)				

TABLE 3.3-3 (Continued)

TABLE NOTATION

Trip function may be bypassed in this MODE below P-11.

Trip function may be bypassed in this MODE below P-12.

** Applies to Functional Unit 8 items c and d.

*** The automatic actuation logic includes two redundant solenoid operated vent valves for each Main Steam Isolation Valve. One vent valve on any one Main Steam Isolation Valve may be isolated without affecting the function of the automatic actuation logic provided the remaining seven solenoid vent valves remain OPERABLE. The isolated MSIV vent valve shall be returned to OPERABLE status upon the first entry into MODE 5 following determination that the vent valve is inoperable. For any condition where more than one of the eight solenoid vent valves are inoperable, entry into ACTION 20 is required.

ACTION STATEMENTS

ACTION 13 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 6 hours or, be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1 provided the other channel is OPERABLE.

ACTION 14 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed until performance of the next required CHANNEL FUNCTIONAL TEST, provided the inoperable channel is placed in the tripped condition within 1 hour.

ACTION 15 - NOT USED

ACTION 16 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is demonstrated by CHANNEL CHECK within 6 hours; one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1.

ACTION 17 - With less than the Minimum Channels OPERABLE, operations may continue provided the containment purge and exhaust valves are maintained closed.

ACTION 18 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.3-3 (Continued)

ACTION 19 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirements is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.2.1.1.

ACTION 20 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 6 hours or, be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1 provided the other channel is OPERABLE.

ACTION 21 - With the number of OPERABLE channels one less than the Minimum Number of Channels, operation may proceed provided that the inoperable channel is restored to OPERABLE within 72 hours.

ACTION 22 - NOT USED

ACTION 23 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES INTERLOCKS

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-11	With 2 of 3 pressurizer pressure channels ≥ 1925 psig.	P-11 prevents or defeats manual block of safety injection actuation on low pressurizer pressure.
P-12	With 3 of 4 T_{avg} channels at a setpoint of 543°F and T_{avg} increasing (with an allowable setpoint value ≤545°F)	P-12 prevents or defeats manual block of safety injection actuation high steam line flow and low steam line pressure.
	With 2 of 4 T_{avg} channels at a setpoint of 543°F and T_{avg} decreasing (with an allowable setpoint value ≥541°F)	Allows manual block of safety injection actuation on high steam line flow and low steam line pressure. Causes steam line isolation on high steam flow. Affects steam dump blocks.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High	≤4.0 psig	≤4.5 psig
d. Pressurizer Pressure--Low	≥1765 psig	≥1755 psig
e. Differential Pressure Between Steam Lines--High	≤100 psi	≤112 psi
f. Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low or Steam Line Pressure--Low	≤A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load $T_{avg} \geq 543°F$ ≥ 600 psig steam line pressure	≤A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load $T_{avg} \geq 541°F$ ≥ 579 psig steam line pressure

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. CONTAINMENT SPRAY		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
3. CONTAINMENT ISOLATION		
a. Phase "A" Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable	Not Applicable
b. Phase "B" Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable
3. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
c. Containment Ventilation Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Atmosphere Gaseous Radioactivity	Per Table 3.3-6	
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
d. Steam Flow in Two Steam Lines--High Coincident with Tavg -- Low-Low or Steam Line Pressure -- Low	≤ a function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load.	≤ a function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load.
	Tavg ≥ 543°F	Tavg ≥ 541°F
	≥ 600 psig steam line pressure	≥ 579 psig steam line pressure

TABLE 3.3-4 (continued)
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
5. TURBINE TRIP AND FEEDWATER ISOLATION		
A. Steam Generator Water Level -- High-High	≤ 67% of narrow range instrument span each steam generator	≤ 68% of narrow range instrument span each steam generator
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC)	Not Applicable	Not Applicable
7. UNDERVOLTAGE, VITAL BUS		
a. Loss of Voltage	≥ 70% of bus voltage	≥ 65% of bus voltage
b. Sustained Degraded Voltage	≥ 94.6% of bus voltage for ≤ 13 seconds	≥ 94% of bus voltage for ≤ 15 seconds
8. AUXILIARY FEEDWATER		
a. Automatic Actuation Logic	Not Applicable	Not Applicable
b. NOT USED		
c. Steam Generator Water Level--Low-Low	≥ 14.0% of narrow range instrument span each steam generator	≥ 13.0% of narrow range instrument span each steam generator
d. Undervoltage - RCP	≥ 70% RCP bus voltage	≥ 65% RCP bus voltage
e. S.I.	See 1 above (All S.I. setpoints)	
f. Trip of Main Feedwater Pumps	Not Applicable	Not Applicable
g. Station Blackout	See 6 and 7 above (SEC and Undervoltage, Vital Bus)	

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TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION				
a. Manual Initiation	N.A.	N.A.	R*	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure-High	S	R	Q(3)	1,2,3
d. Pressurizer Pressure--Low	S	R	Q	1,2,3
e. Differential Pressure Between Steam Lines--High	S	R	Q	1,2,3
f. Steam Flow in Two Steam Lines--High coincident with Tavg--Low-Low or Steam Line Pressure-Low	S	R	Q	1,2,3
2. CONTAINMENT SPRAY				
a. Manual Initiation	N.A.	N.A.	R	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure--High-High	S	R	Q(3)	1,2,3

* A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
3. CONTAINMENT ISOLATION				
a. Phase "A" Isolation				
1. Manual	N.A.	N.A.	R	1,2,3,4
2. From Safety Injection Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
b. Phase "B" Isolation				
1. Manual	N.A.	N.A.	R	1,2,3,4
2. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
3. Containment Pressure--High-High	S	R	Q(3)	1,2,3
c. Containment Ventilation Isolation				
1. Manual	N.A.	N.A.	R	1,2,3,4
2. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
3. Containment Atmosphere Gaseous Radioactivity - High		Per table 4.3-3		

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4. STEAM LINE ISOLATION				
a. Manual	N.A.	N.A.	R	1,2,3**
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3
c. Containment Pressure--High-High	S	R	Q(3)	1,2,3
d. Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low or Steam Line Pressure--Low	S	R	Q	1,2,3
5. TURBINE TRIP AND FEEDWATER ISOLATION				
a. Steam Generator Water Level--High-High	S	R	Q	1,2,3
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC) LOGIC				
a. Inputs	N.A.	N.A.	M(6)	1,2,3,4
b. Logic, Timing and Outputs *	N.A.	N.A.	M(1)	1,2,3,4
7. UNDERVOLTAGE, VITAL BUS				
a. Loss of Voltage	S	R	M	1,2,3
b. Sustained Degraded Voltage	S	R	M	1,2,3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
8. AUXILIARY FEEDWATER				
a. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3
b. NOT USED				
c. Steam Generator Water Level--Low-Low	S	R	Q	1,2,3
d. Undervoltage - RCP	S	R	Q	1,2
e. S.I.	See 1 above (All S.I. surveillance requirements)			
f. Trip of Main Feedwater Pumps	N.A.	N.A.	R	1
g. Station Blackout	See 6b and 7 above (SEC and U/V Vital Bus)			

TABLE 4.3-2 (Continued)

TABLE NOTATION

* Outputs are up to, but not including, the output relays.

** The provisions of Specification 4.0.4 are not applicable.

(1) Each logic channel shall be tested at least once per 62 days on a STAGGERED TEST BASIS. The CHANNEL FUNCTION TEST of each logic channel shall verify that its associated diesel generator automatic load sequence timer is OPERABLE with the interval between each load block within 1 second of its design interval.

(2) Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(3) The CHANNEL FUNCTIONAL TEST shall include exercising the transmitter by applying either a vacuum or pressure to the appropriate side of the transmitter.

(4) NOT USED

(5) NOT USED

(6) Inputs from Undervoltage, Vital Bus, shall be tested monthly. Inputs from Solid State Protection System shall be tested every 62 days on a STAGGERED TEST BASIS.

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels shown in Table 3.3-6 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel alarm/trip setpoint exceeding the value shown in Table 3.3-6, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION shown in Table 3.3-6.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-3.

TABLE 3.3-6
RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. AREA MONITORS					
a. Fuel Storage Area	1	*	≤15 mR/hr	10^{-1}-10^{4} mR/hr	19
2. PROCESS MONITORS					
a. Containment					
1) Gaseous Activity					
a) Purge & Pressure - Vacuum Relief Isolation	1#	1,2,3,4&5	per ODCM	10^{1}-10^{6} cpm	23
b) RCS Leakage Detection	1	1,2,3&4	N/A	10^{1}-10^{6} cpm	20
2) Air Particulate Activity					
a) (NOT USED)					
b) RCS Leakage Detection	1	1,2,3&4	N/A	10^{1}-10^{6} cpm	20

* With fuel in the storage pool or building.

\# The plant vent noble gas monitor may also function in this capacity when the purge/pressure-vacuum relief isolation valves are open.

TABLE 3.3-6 (Continued)
RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
2. PROCESS MONITORS					
b. Noble Gas Effluent Monitors					
1) Medium Range Auxiliary Building Exhaust System (Plant Vent)	1	1,2,3&4	$\leq 3.0\times10^{-2}$ µCi/cm^3 (Alarm only)	10^{-3}-10^{1} µCi/cm^3	23
2) High Range Auxiliary Building Exhaust System (Plant Vent)	1	1,2,3&4	$\leq 1.0\times10^{2}$ µCi/cm^3	10^{-1}-10^{5} µCi/cm^3 (Alarm only)	23
3) Condenser Exhaust System	1	1,2,3&4	$\leq 1.27\times10^{4}$ cpm (Alarm only)	1-10^{6} cpm	23
3. CONTROL ROOM					
a. Air Intake - Radiation Level	2/Intake##	**	$\leq 2.48\times10^{3}$ cpm	10^{1}-10^{7} cpm	24, 25

Control Room air intakes shared between Unit 1 and 2.

** ALL MODES and during movement of irradiated fuel assemblies and during CORE ALTERATIONS.

TABLE 3.3-6 (Continued)

TABLE NOTATION

ACTION 19 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 20 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.6.1.

ACTION 22 - (Not Used)

ACTION 23 - With the number of OPERABLE Channels less than required by the Minimum Channels OPERABLE requirements, initiate the preplanned alternate method of monitoring the appropriate parameter(s), within 72 hours, and:

1) either restore the inoperable Channel(s) to OPERABLE status within 7 days of the event, or

2) prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 24 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel(s) to OPERABLE status within 7 days or initiate and maintain operation of the Control Room Emergency Air Conditioning System (CREACS) in the pressurization or recirculation mode of operation. CORE ALTERATIONS and movement of irradiated fuel assemblies will be suspended during operation in the recirculation mode.

ACTION 25 - With no channels OPERABLE in a Control Room air intake, immediately initiate and maintain operation of the CREACS in the pressurization or recirculation mode of operation. CORE ALTERATIONS and movement of irradiated fuel assemblies will be suspended during operation in the recirculation mode.

Table 4.3-3

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNELS CHECKS	SOURCE CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. AREA MONITORS					
a. Fuel Storage Area	S	M	R	Q	*
2. PROCESS MONITORS					
a. Containment Monitors					
1) Gaseous Activity					
a) Purge & Pressure Vacuum Relief Isolation	S	M	R	Q	1, 2, 3, 4 & 5
b) RCS Leakage Detection	S	M	R	Q	1, 2, 3 & 4
2) Air Particulate Activity					
a) (NOT USED)					
b) RCS Leakage Detection	S	M	R	Q	1, 2, 3 & 4

*With fuel in the storage pool or building.

TABLE 4.3-3 (Continued)
RADIATION MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNELS CHECKS	SOURCE CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
2. PROCESS MONITORS					
b. Noble Gas Effluent Monitors					
1) Medium Range Auxiliary Building Exhaust System (Plant Vent)	S	M	R	Q	1, 2, 3 & 4
2) High Range Auxiliary Building Exhaust System (Plant Vent)	S	M	R	Q	1, 2, 3 & 4
3) Condenser Exh. Sys.	S	M	R	Q	1, 2, 3 & 4
3. CONTROL ROOM					
a. Air Intake - Radiation Level	S	M	R	Q	**

** ALL MODES and during movement of irradiated fuel assemblies and during CORE ALTERATIONS.

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REMOTE SHUTDOWN INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.5 The remote shutdown monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE with readouts displayed external to the control room.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring channels less than required by Table 3.3-9, either restore the inoperable channel to OPERABLE status within 30 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.5 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Pressurizer Pressure	Hot Shutdown Panel 213	1700-2500 psig	1
2. Pressurizer Level	Hot Shutdown Panel 213	0 - 100%	1
3. Steam Generator Pressure	Hot Shutdown Panel 213	0 - 1200 psig	1/steam generator
4. Steam Generator Level	Hot Shutdown Panel 213	0 - 100%	1/steam generator

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Pressurizer Pressure	M	R
2. Pressurizer Level	M	R
3. Steam Generator Pressure	M	R
4. Steam Generator Level	M	R

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INSTRUMENTATION

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.7 The accident monitoring instrumentation channels shown in Table 3.3-11 shall be operable.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. As shown in Table 3.3-11.

SURVEILLANCE REQUIREMENTS

4.3.3.7 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3-11.

TABLE 3.3-11

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NO. OF CHANNELS	MINIMUM NO. OF CHANNELS	ACTION
1. Reactor Coolant Outlet Temperature - T_{HOT} (Wide Range)	2	1	1, 2
2. Reactor Coolant Inlet Temperature - T_{COLD} (Wide Range)	2	1	1, 2
3. Reactor Coolant Pressure (Wide Range)	2	1	1, 2
4. Pressurizer Water Level	2	1	1, 2
5. Steam Line Pressure	2/Steam Generator	1/Steam Generator	1, 2
6. Steam Generator Water Level (Narrow Range)	2/Steam Generator	1/Steam Generator	1, 2
7. Steam Generator Water Level (Wide Range)	4 (1/Steam Generator)	3 (1/Steam Generator)	1, 2
8. Refueling Water Storage Tank Water Level	2	1	1, 2
9. deleted			
10. Auxiliary Feedwater Flow Rate	4 (1/Steam Generator)	3 (1/Steam Generator)	4, 6
11. Reactor Coolant System Subcooling Margin Monitor	2	1	1, 2
12. PORV Position Indicator	2/valve**	1	1, 2

TABLE 3.3-11 (CONTINUED)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NO. OF CHANNELS	MINIMUM NO. OF CHANNELS	ACTION
13. PORV Block Valve Position Indicator	2/valve**	1	1, 2
14. Pressurizer Safety Valve Position Indicator	2/valve**	1	1, 2
15. Containment Pressure - Narrow Range	2	1	1, 2
16. Containment Pressure - Wide Range	2	1	7, 2
17. Containment Water Level - Wide Range	2	1	7, 2
18. Core Exit Thermocouples	4/core quadrant	2/core quadrant	1, 2
19. Reactor Vessel Level Instrumentation System (RVLIS)	2	1	8, 9
20. Containment High Range Accident Radiation Monitor	2	2	10
21. Main Steamline Discharge (Safety Valves and Atmospheric Steam Dumps) Monitor	1/ MS Line	1/ MS Line	10

(**) Total number of channels is considered to be two (2) with one (1) of the channels being any one (1) of the following alternate means of determining PORV, PORV Block, or Safety Valve position: Tailpipe Temperatures for the valves, Pressurizer Relief Tank Temperature Pressurizer Relief Tank Level OPERABLE.

TABLE 3.3-11 (continued)

TABLE NOTATION

ACTION 1 With the number of OPERABLE accident monitoring channels less than the Required Number of Channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

ACTION 2 With the number of OPERABLE accident monitoring channels less than the MINIMUM Number of Channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in HOT SHUTDOWN within the next 12 hours.

ACTION 3 deleted

ACTION 4 With the number of OPERABLE channels one less than the Required Number of Channels shown in Table 3.3-11, operation may proceed provided that an OPERABLE Steam Generator Wide Range Level channel is available as an alternate means of indication for the Steam Generator with no OPERATABLE Auxiliary Feedwater Flow Rate channel.

ACTION 5 deleted

TABLE 3.3-11 (continued)

TABLE NOTATION

ACTION 6 With the number of OPERABLE channels less than the Minimum Number of channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

ACTION 7 With the number of OPERABLE channels one less than the Required Number of Channels shown in Table 3.3-11, operation may proceed until the next CHANNEL CALIBRATION (which shall be performed upon the next entry into MODE 5, COLD SHUTDOWN).

ACTION 8 With one RVLIS channel inoperable, restore the RVLIS channel to OPERABLE status within 30 days, or submit a special report in accordance with Specification 6.9.4.

ACTION 9 With both RVLIS channels inoperable, restore one channel to OPERABLE status within 7 days or submit a special report in accordance with Specification 6.9.4.

ACTION 10 With the number of OPERABLE Channels less than required by the minimum channels OPERABLE requirements, initiate the preplanned alternate method of monitoring the appropriate parameter within 72 hours, and:

1) either restore the inoperable Channel(s) to OPERABLE status within 7 days of the event, or

2) prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the actions taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

TABLE 4.3-11
SURVEILLANCE REQUIREMENTS FOR
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	CHANNEL CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Reactor Coolant Outlet Temperature - T_{HOT} (Wide Range)	M	R	N.A.
2. Reactor Coolant Inlet Temperature - T_{COLD} (Wide Range)	M	R	N.A.
3. Reactor Coolant Pressure (Wide Range)	M	R	N.A.
4. Pressurizer Water Level	M	R	N.A.
5. Steam Line Pressure	M	R	N.A.
6. Steam Generator Water Level (Narrow Range)	M	R	N.A.
7. Steam Generator Water Level (Wide Range)	M	R	N.A.
8. Refueling Water Storage Tank Water Level	M	R	N.A.
9. deleted			
10. Auxiliary Feedwater Flow Rate	S/U#	R	N.A.
11. Reactor Coolant System Subcooling Margin Monitor	M	N.A.*	N.A.

#Auxiliary Feedwater System is used on each startup and flow rate indication is verified at that time.

*The instruments used to develop RCS subcooling margin are calibrated on an 18 month cycle; the monitor will be compared quarterly with calculated subcooling margin for known input values.

TABLE 4.3-11 (Continued)
SURVEILLANCE REQUIREMENTS FOR
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
12. PORV Position Indicator	M	N.A.	R
13. PORV Block Valve Position Indicator	M	N.A.	Q*
14. Pressurizer Safety Valve Position Indicator	M	N.A.	R
15. Containment Pressure - Narrow Range	M	R	N.A.
16. Containment Pressure - Wide Range	M	R	N.A.
17. Containment Water Level - Wide Range	M	R**	N.A.
18. Core Exit Thermocouples	M	R	N.A.
19. Reactor Vessel Level Instrumentation System (RVLIS)	M	R	N.A.
20. Containment High Range Accident Radiation Monitor	S	R	Q
21. Main Steamline Discharge (Safety Valves and Atmospheric Steam Dumps) Monitor	S	R	Q

*Unless the block valve is closed in order to meet the requirements of Action b, or c in specification 3.4.3.

** A one-time extension to this surveillance requirement is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

INSTRUMENTATION

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.8 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3-12 shall be operable to ensure that the limits of ODCM Control 3.11.1.1 are not exceeded.

APPLICABILITY: At all times.

ACTION:

a. Not Used

b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3-12. Exert best efforts to return the instrument to OPERABLE status within 30 days and, if unsuccessful, explain in the next annual radioactive effluent release report why the inoperability was not corrected in a timely manner.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.8 Each radioactive liquid effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3-12.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Not Used		
2. Not Used		
3. Not Used		
4. TANK LEVEL INDICATING DEVICES		
a. Temporary Outside Storage Tanks as Required	1	30

TABLE NOTATION

ACTION 26 - Not Used

ACTION 27 - Not Used

ACTION 28 - Not Used

ACTION 29 - Not Used

ACTION 30 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, liquid additions to this tank may continue for up to 30 days provided the tank liquid level is estimated during all liquid additions to the tank.

TABLE 4.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Not Used				
2. Not Used				
3. Not Used				
4. TANK LEVEL INDICATING DEVICES**				
a. Temporary Outside Storage Tanks as Required	D*	N.A.	R	Q

TABLE NOTATION

* During liquid additions to the tank.

** If tank level indication is not provided, verification will be done by visual inspection.

Pages 3/4 3-62 Through 3/4 3-69 Deleted

LIMITING CONDITION FOR OPERATION

3.3.3.14 The Power Distribution Monitoring System (PDMS) shall be OPERABLE with:

a. A minimum of the following inputs from the plant available for use by the PDMS as defined in Table 3.3-14.

1. Control Bank Position
2. T_{cold}
3. Reactor Power Level
4. NIS Power Range Detector Section Signals

b. Core Exit Thermocouples (T/C) meeting the criteria:

1. At least 25% operable T/C with at least 2 T/C per quadrant, and
2. The T/C pattern has coverage of all interior fuel assemblies (no face along the baffle), within a chess knight's move, radially, from a responding, calibrated T/C, or
3. At least 25%, operable T/C with at least 2 T/C per quadrant, and the installed PDMS calibration was determined within the last 31 Effective Full Power Days (EFPD).
4. The T/C temperatures used by the PDMS are calibrated via cross calibration with the loop temperature measurement RTDs, and using the T/C flow mixing factors determined during installed PDMS calibration.

c. An installed PDMS calibration satisfying the criteria:

1. The initial calibration in each operating cycle is determined using measurements from at least 75% of the incore movable detector thimbles obtained at a THERMAL POWER greater than 25% of RATED THERMAL POWER.
2. The calibration is determined using measurements from at least 50% of the incore movable detector thimbles at any time except as specified in 3.3.3.14.c.1, and
3. The calibration is determined using a minimum of 2 detector thimbles per core quadrant.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILTY: MODE 1, above 25% RATED THERMAL POWER (RTP)

ACTION:

With any of the operability criteria listed in 3.3.3.14.a, 3.3.3.14.b, or 3.3.3.14.c not met, either correct the deficient operability condition, or declare the PDMS inoperable and use the incore movable detector system, satisfying the OPERABILITY requirements listed in Specification 3.3.3.2, to obtain any required core power distribution measurements. Increase the measured core peaking factors using the values listed in the COLR for the PDMS inoperable condition.

The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.14.1 The operability criteria listed in 3.3.3.14.a, 3.3.3.14.b, and 3.3.3.14.c shall be verified to be satisfied prior to acceptance of the PDMS core power distribution measurement results.

4.3.3.14.2 Calibration of the PDMS is required:

a. At least once every 180 Effective Full Power Days when the minimum number and core coverage criteria as defined in 3.3.3.14.b.1 and 3.3.3.14.b.2 are satisfied, or

b. At least once every 31 Effective Full Power Days when only the minimum number criterion as defined in 3.3.3.14.b.3 is satisfied.

TABLE 3.3-14

REQUIRED PDMS PLANT INPUT INFORMATION

PLANT INPUT INFORMATION	AVAILABLE INPUTS	MINIMUM NO. OF VALID INPUTS	APPLICABLE MODES
Control Bank Position	4	4^a	1^c
T_{cold}	4	2	1^c
Reactor Power Level	3	1^b	1^c
NIS Power Range Excore Detector Section Signals	8	6^d	1^c

TABLE NOTATIONS

a. Determined from either valid Demand Position or the average of the valid individual RCCA position indications for all RCCAs in the Control Bank.

b. Determined from either the reactor THERMAL POWER derived using a valid secondary calorimetric measurement, the average NIS Power Range Detector Power, or the average RCS Loop ΔT.

c. Greater than 25% RTP.

d. Comprised of an upper and lower detector section signal per Power Range Channel; a minimum of 3 OPERABLE channels required.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 REACTOR COOLANT LOOPS

NORMAL OPERATION

LIMITING CONDITION FOR OPERATION

3.4.1.1 All reactor coolant loops shall be in operation.

APPLICABILITY: MODES 1 and 2*

ACTION:

With less than the above required reactor coolant loops in operation, be in at least HOT STANDBY within 1 hour.

SURVEILLANCE REQUIREMENT

4.4.1.1 The above required reactor coolant loops shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

*See Special Test Exception 3.10.4.

REACTOR COOLANT SYSTEM

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 a. At least two of the reactor coolant loops listed below shall be OPERABLE:

1. Reactor Coolant Loop 11 and its associated steam generator and reactor coolant pump,

2. Reactor Coolant Loop 12 and its associated steam generator and reactor coolant pump,

3. Reactor Coolant Loop 13 and its associated steam generator and reactor coolant pump,

4. Reactor Coolant Loop 14 and its associated steam generator and reactor coolant pump.

b. At least one of the above coolant loops shall be in operation* when the rod control system is deenergized**.

c. All of the above coolant loops shall be in operation when the rod control system is energized**.

APPLICABILITY: MODE 3

ACTION:

a. With less than the above required reactor coolant loops OPERABLE, restore the required loops to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 At least the above required reactor coolant pumps, if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.2.2 At least one cooling loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

4.4.1.2.3 The required steam generator(s) shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 5% (narrow range) at least once per 12 hours.

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*All reactor coolant pumps may be de-energized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration (2) core outlet temperature is maintained at least 10°F below saturation temperature, and (3) the rod control system is de-energized**

**The rod control system shall be considered de-energized when one or more of the following conditions exist:

1) Both Rod Drive MG set motor breakers are open.

2) Both Rod Drive MG set generator breakers are open.

3) A combination of at least three of the Reactor Trip and/or Reactor Trip Bypass Breakers are open.

If none of the above conditions for de-energizing the rod control system are met; the system shall be considered energized.

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.3 a. At least two of the coolant loops listed below shall be OPERABLE:

1. Reactor Coolant Loop (11) and its associated steam generator and reactor coolant pump,*

2. Reactor Coolant Loop (12) and its associated steam generator and reactor coolant pump,*

3. Reactor Coolant Loop (13) and its associated steam generator and reactor coolant pump,*

4. Reactor Coolant Loop (14) and its associated steam generator and reactor coolant pump,*

5. Residual Heat Removal Loop (11),

6. Residual Heat Removal Loop (12).

b. At least one of the above coolant loops shall be in operation.**

APPLICABILITY: MODE 4

ACTION:

a. With less than the above required loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible; be in COLD SHUTDOWN within 20 hours.

b. With no coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop to operation.

*A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to (312)°F unless 1) the pressurizer water volume is less than 1650 cubic feet (93.2% of pressurizer level indication) or 2) the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

**All reactor coolant pumps and residual heat removal pumps may be deenergized for up to 1 hour provided 1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required residual heat removal loop(s) shall be determined OPERABLE per the inservice testing schedule.

4.4.1.3.2 The required reactor coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.3.3 The required steam generator(s) shall be determined OPERABLE by verifying secondary side level to be greater than or equal to 5% of narrow range at least once per 12 hours.

4.4.1.3.4 At least one coolant loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.4 Two# residual heat removal loops shall be OPERABLE* and at least one RHR loop shall be in operation.**

APPLICABILITY: MODE 5.##

ACTION:

a. With less than the above required loops operable, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4 At least one residual heat removal loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

One RHR loop may be inoperable for up to two hours for surveillance testing, provided the other RHR loop is OPERABLE and in operation. Additionally, four filled reactor coolant loops, with at least two steam generators with their secondary side water levels greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop.

A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to 312 °F unless 1) the pressurizer water volume is less than 1650 cubic feet (equivalent to approximately 93.2% of level), or 2) the secondary water temperature of each steam generator is less than 50 °F above each of the RCS cold leg temperatures.

* Systems supporting RHR loop operability may be excepted as follows:

a. The normal or emergency power source may be inoperable.

** The residual heat removal pumps may be de-energized for up to 2 hours provided 1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and 2) core outlet temperature is maintained at least 10 °F below saturation temperature.

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3/4.4.2 SAFETY VALVES

SAFETY VALVES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer code safety valve shall be OPERABLE* with a lift setting of 2485 psig ± 3%.**,***

APPLICABILITY: Mode 4 and 5

ACTION:

With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE RHR loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

* While in Mode 5, an equivalent size vent pathway may be used provided that the vent pathway is not isolated or sealed.

** The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

*** Following testing the lift setting shall be reset to within ± 1%.

3/4.4.2 SAFETY VALVES

SAFETY VALVES - OPERATING

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer code safety valve shall be OPERABLE with a lift setting of 2485 psig ± 3%.*,**

APPLICABILITY: MODES 1, 2 and 3.

ACTION:
With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes, or be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional Surveillance Requirements other than those required by Specification 4.0.5

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* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** Following testing the lift setting shall be reset to within ± 1%.

REACTOR COOLANT SYSTEM

3/4.4.3 RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.3 Two power relief valves (PORVs) and their associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or both PORVs inoperable because of excessive seat leakage, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) with power maintained to the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one PORV inoperable due to causes other than excessive seat leakage, within 1 hour either restore the PORV to OPERABLE status or close its associated block valve and remove power from the block valve; restore the PORV to OPERABLE status within the following 72 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With both PORVs inoperable due to causes other than excessive seat leakage, within 6 hours either restore at least one PORV to OPERABLE status or close the associated block valves and remove power from the block valves and be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours. Restore the remaining PORV to OPERABLE status within 72 hours from failure of that valve to meet the Limiting Condition for Operation.

d. With one block valve inoperable, within 1 hour restore the block valve to OPERABLE status or place the associated PORV in manual control; restore the block valve to operable status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

e. With both block valves inoperable, within 1 hour restore the block valves to OPERABLE status or place the associated PORVs in manual control; restore at least one block valve to OPERABLE status within the next 6 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours. Restore the remaining block valve to OPERABLE status within 72 hours from failure of that valve to meet the Limiting Condition for Operation.

3/4.4.3 RELIEF VALVES

SURVEILLANCE REQUIREMENTS

4.4.3.1 In addition to the requirements of Specification 4.0.5, each PORV shall be demonstrated OPERABLE at least once per 18 months by:

a. Operating the PORV through one complete cycle of full travel during MODES 3 or 4, and

b. Operating solenoid valves, air control valves, and check valves on associated air accumulators in PORV control systems through one complete cycle of full travel, and

c. Performing a CHANNEL CALIBRATION of the actuation instrumentation.

4.4.3.2 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel unless the block valve is closed in order to meet the requirements of ACTION b, or c in Specification 3.4.3.

REACTOR COOLANT SYSTEM

3/4.4.4 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.4 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1650 cubic feet (92% indicated level), and at least two groups of pressurizer heaters each having a capacity of ≥ 150 kw and capable of being powered from an emergency power supply.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the pressurizer inoperable due to an inoperable emergency power supply to the pressurizer heaters either restore the inoperable emergency power supply within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.4.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.4.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by measuring circuit current at least once each refueling outage.

4.4.4.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by manually transferring power from the normal to the emergency power supply and energizing the heaters.

STEAM GENERATOR (SG) TUBE INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.5 SG tube integrity shall be maintained and all SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a.* With one or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program:

1. Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection within 7 days; and

2. Plug the affected tube(s) in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following the next refueling outage or SG tube inspection.

b. With SG tube integrity not maintained or the required Action of a. above not met, be in at least HOT STANDBY within 6 hours and in at least COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.5.1 Verify SG tube integrity in accordance with the Steam Generator Program.

4.4.5.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following a SG tube inspection.

*Separate Action is allowed for each SG tube.

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3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System leakage detection systems shall be OPERABLE:

a. The containment atmosphere particulate radioactivity monitoring system,

b. The containment sump level monitoring system, and

c. Either the containment fan cooler condensate flow rate or the containment atmosphere gaseous radioactivity monitoring system.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only two of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required gaseous and/or particulate radioactivity monitoring system is inoperable; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The leakage detection systems shall be demonstrated OPERABLE by:

a. Containment atmosphere particulate and gaseous (if being used) monitoring systems-performance of CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies specified in Table 4.3-3.

b. Containment sump level and containment fan cooler condensate flow rate (if being used) monitoring systems-performance of CHANNEL CALIBRATION at least once per 18 months.

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 GPM UNIDENTIFIED LEAKAGE,

c. 150 gallons per day primary-to-secondary leakage through any one steam generator, and

d. 10 GPM IDENTIFIED LEAKAGE from the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, 3 and 4

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE or primary-to-secondary leakage not within limit, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE and primary-to-secondary leakage, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by;

a. Monitoring the containment atmosphere particulate radioactivity monitor at least once per 12 hours.

b. Monitoring the containment sump inventory at least once per 12 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c.* Verifying primary-to-secondary leakage is ≤ 150 gallons per day through any one steam generator at least once per 72 hours during steady state operation.

d.* Performance of a Reactor Coolant System water inventory balance** at least once per 72 hours. The water inventory balance shall be performed with the plant at steady state conditions. The provisions of specification 4.0.4 are not applicable for entry into Mode 4, and

e. Monitoring the reactor head flange leakoff system at least once per 24 hours.

*Not required to be completed until 12 hours after establishment of steady state operation.

**Not applicable to primary-to-secondary leakage.

REACTOR COOLANT SYSTEM

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES LIMITING CONDITION FOR OPERATION

3.4.6.3 Reactor Coolant System Pressure Isolation Valves specified in Table 4.4-3 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the specified limit in Table 4.4-3, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.3 Each Reactor Coolant System Pressure Isolation Valve specified in Table 4.4-3 shall be demonstrated OPERABLE pursuant to Specification 4.0.5, except that in lieu of any leakage testing required by Specification 4.0.5, each valve shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once per 18 months.

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 72 hours or more and if leakage testing has not been performed in the previous 9 months.

c. Prior to returning the valve to service following maintenance repair or replacement work on the valve.

d. For the Residual Heat Removal and Safety Injection Systems hot and cold leg injection valves and accumulator valves listed in Table 4.4-3 the testing will be done within 24 hours following valve actuation due to automatic or manual action or flow through the valve. For all other systems testing will be done once per refueling.

   The provisions of specification 4.0.4 are not applicable for entry into MODE 3 or 4.

TABLE 4.4-3

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

System	Valve No.	Maximum[a] [b] Allowable Leakage
Low Pressure Safety Injection		≤ 5.0 GPM each valve
Loop 11, cold leg	11SJ56	≤ 5.0 GPM each valve
	11SJ43	≤ 5.0 GPM each valve
Loop 12, cold leg	12SJ56	≤ 5.0 GPM each valve
	12SJ43	≤ 5.0 GPM each valve
Loop 13, cold leg	13SJ56	≤ 5.0 GPM each valve
	13SJ43	≤ 5.0 GPM each valve
Loop 13, hot leg	13SJ156	≤ 5.0 GPM each valve
	13RH27	≤ 5.0 GPM each valve
Loop 14, cold leg	14SJ56	≤ 5.0 GPM each valve
	14SJ43	≤ 5.0 GPM each valve
Loop 14, hot leg	14SJ156	≤ 5.0 GPM each valve
	14RH27	≤ 5.0 GPM each valve
Intermediate Pressure Safety Injection		≤ 5.0 GPM each valve
Loop 11, cold leg	11SJ144	≤ 5.0 GPM each valve
Loop 11, hot leg	11SJ156	≤ 5.0 GPM each valve
	11SJ139	≤ 5.0 GPM each valve
Loop 12, cold leg	12SJ144	≤ 5.0 GPM each valve
Loop 12, hot leg	12SJ156	≤ 5.0 GPM each valve
	12SJ139	≤ 5.0 GPM each valve
Loop 13, cold leg	13SJ144	≤ 5.0 GPM each valve
Loop 13, hot leg	13SJ156	≤ 5.0 GPM each valve
	13SJ139	≤ 5.0 GPM each valve
Loop 14, cold leg	14SJ144	≤ 5.0 GPM each valve
Loop 14, hot leg	14SJ156	≤ 5.0 GPM each valve
	14SJ139	≤ 5.0 GPM each valve
Safety Injection Accumulators to cold leg		
loop 11, cold leg	11SJ55	≤ 5.0 GPM each valve
loop 12, cold leg	12SJ55	≤ 5.0 GPM each valve
loop 13, cold leg	13SJ55	≤ 5.0 GPM each valve
loop 14, cold leg	14SJ55	≤ 5.0 GPM each valve
Safety Injection Boron Injection to cold legs		
loop 11, cold leg	11SJ17	≤ 5.0 GPM each valve
loop 12, cold leg	12SJ17	≤ 5.0 GPM each valve
loop 13, cold leg	13SJ17	≤ 5.0 GPM each valve
loop 14, cold leg	14SJ17	≤ 5.0 GPM each valve
	1SJ150	≤ 5.0 GPM each valve
RHR Suction		
loop 11	1RH1	≤ 5.0 GPM each valve
loop 11	1RH2	≤ 5.0 GPM each valve

TABLE 4.4-3 (CONT'D)

(a) 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable. However, for initial tests, or tests following valve repair or replacement, leakage rates less than or equal to 5.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

(b) Minimum differential test pressure shall not be less than 150 psid.

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REACTOR COOLANT SYSTEM

SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the primary coolant shall be limited to:

a. ≤ 1.0 μCi/gram DOSE EQUIVALENT I-131, and

b. ≤ 100/Ē μCi/gram.

APPLICABILITY: MODES 1, 2, 3, 4 and 5

ACTION:

MODES 1, 2 and 3*

a. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in at least HOT STANDBY with T_{avg} < 500°F within 6 hours.

b. With the specific activity of the primary coolant > 100/Ē μCi/gram, be in at least HOT STANDBY with T_{avg} < 500°F within 6 hours.

c. LCO 3.0.4.c is applicable.

MODES 1, 2, 3, 4 and 5

a. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 or > 100/Ē μCi/gram, perform the sampling and analysis requirements of item 4a of Table 4.4-4 until the specific activity of the primary coolant is restored to within its limits.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

*With T_{avg} ≥ 500°F.

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TABLE 4.4-4

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Activity Determination	At least once per 72 hours	1, 2, 3, 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination	1 per 6 months*	1
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135	a) Once per 4 hours, whenever the specific activity exceeds 1.0 μCi/gram DOSE EQUIVALENT I-131 or 100/$\bar{E}$ μCi/gram, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 & 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.	1, 2, 3

#Until the specific activity of the primary coolant system is restored within its limits.
*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

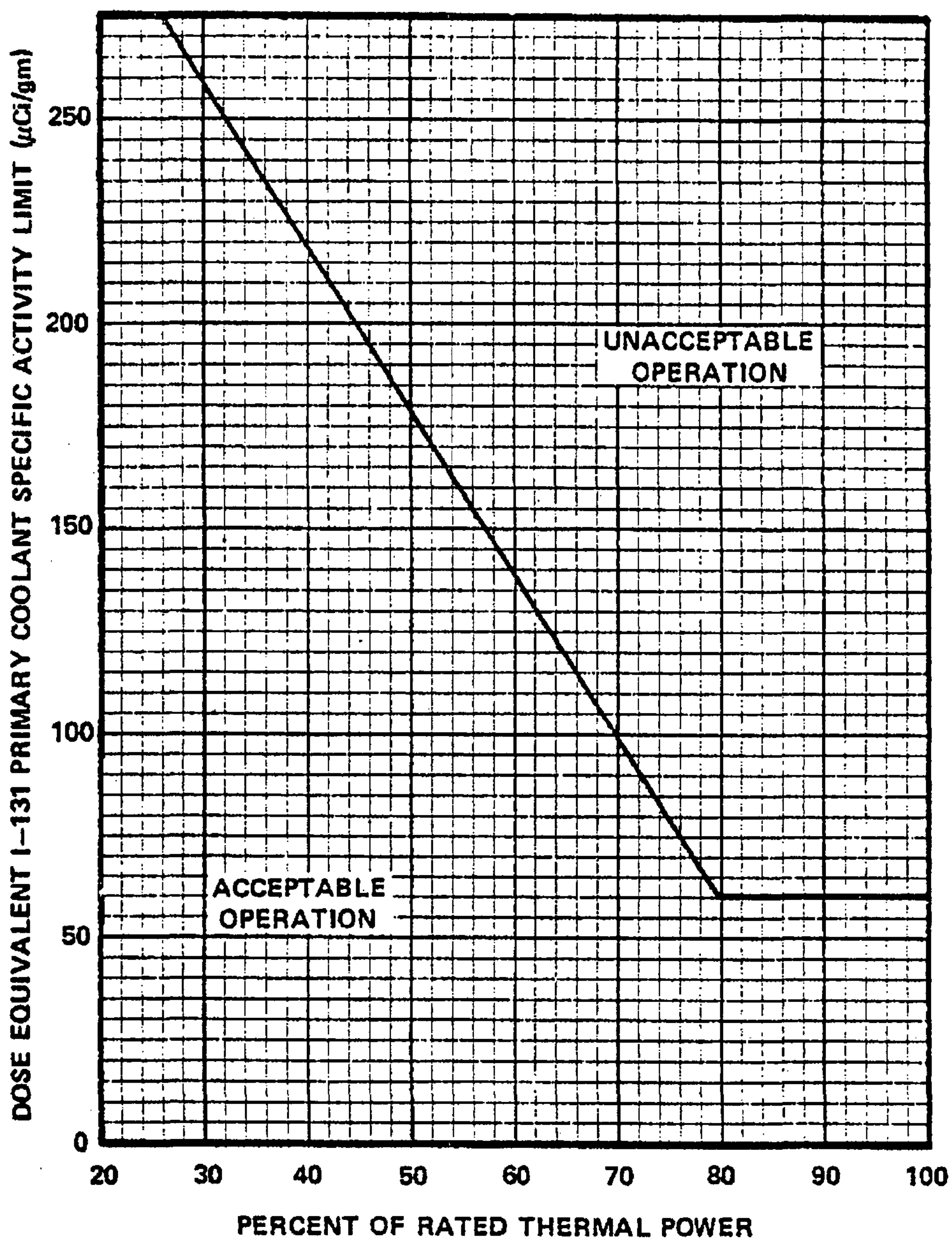

FIGURE 3.4-1

DOSE EQUIVALENT I–131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity > 1.0µCi/gram Dose Equivalent I-131

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.9.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figures 3.4-2 and 3.4-3 during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 100°F in any one hour period, and

c. A maximum temperature change of $\leq$ 5°F in any one hour period, during hydrostatic testing operations above system design pressure.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limit within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the fracture toughness properties of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the RCS T_{avg} and pressure to less than 200°F and 500 psig, respectively, within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.1.1 The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

4.4.9.1.2 The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties, at the intervals required by 10 CFR 50, Appendix H. The results of these examinations shall be used to update Figures 3.4-2 and 3.4-3.

Limiting Material Property

	@1/4T Weld 3-042C	@3/4T Plate B2402-1
Initial RT_{NDT}	-56°F	45°F
RT_{NDT} after 32 EFPY	232°F	171°F

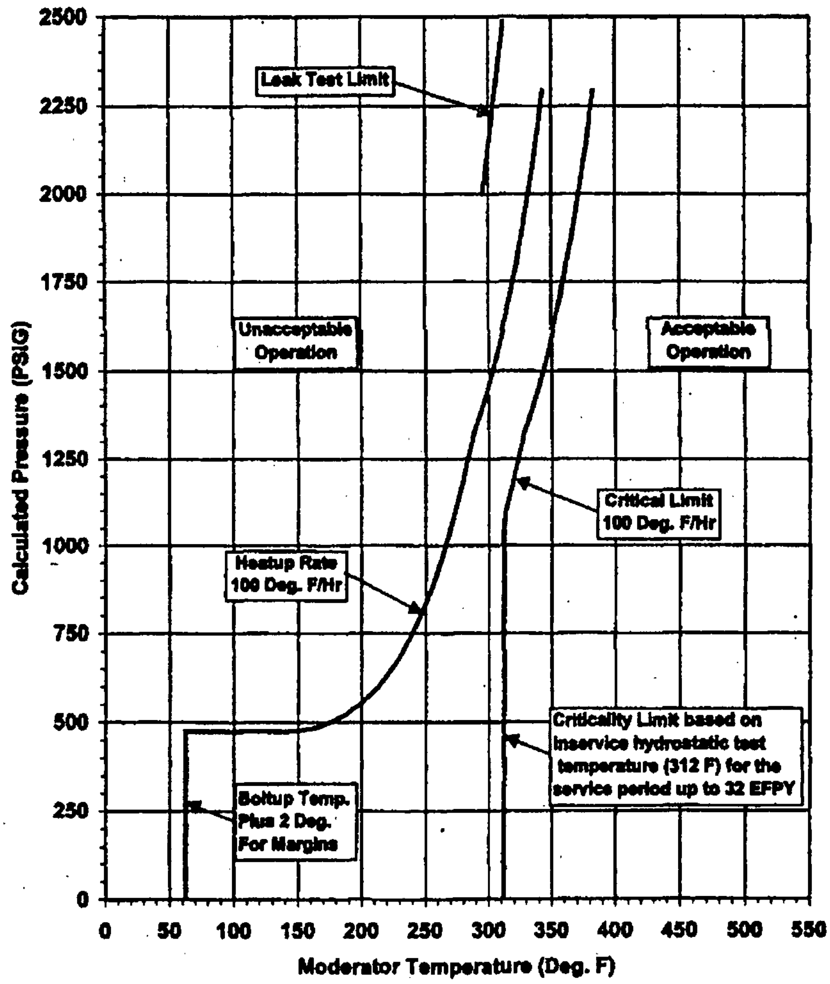

Figure 3.4-2 Salem Unit 1 Reactor Coolant System Heatup Limitations Applicable for Heatup Rates up to 100°F/HR for the Service Period up to 32 EFPY (with uncertainties for instrumentation errors).

Limiting Material Property		
	@1/4T Weld 3-042C	@3/4T Plate B2402-1
Initial RT_{NDT}	-56°F	45°F
RT_{NDT} after 32 EFPY	232°F	171°F

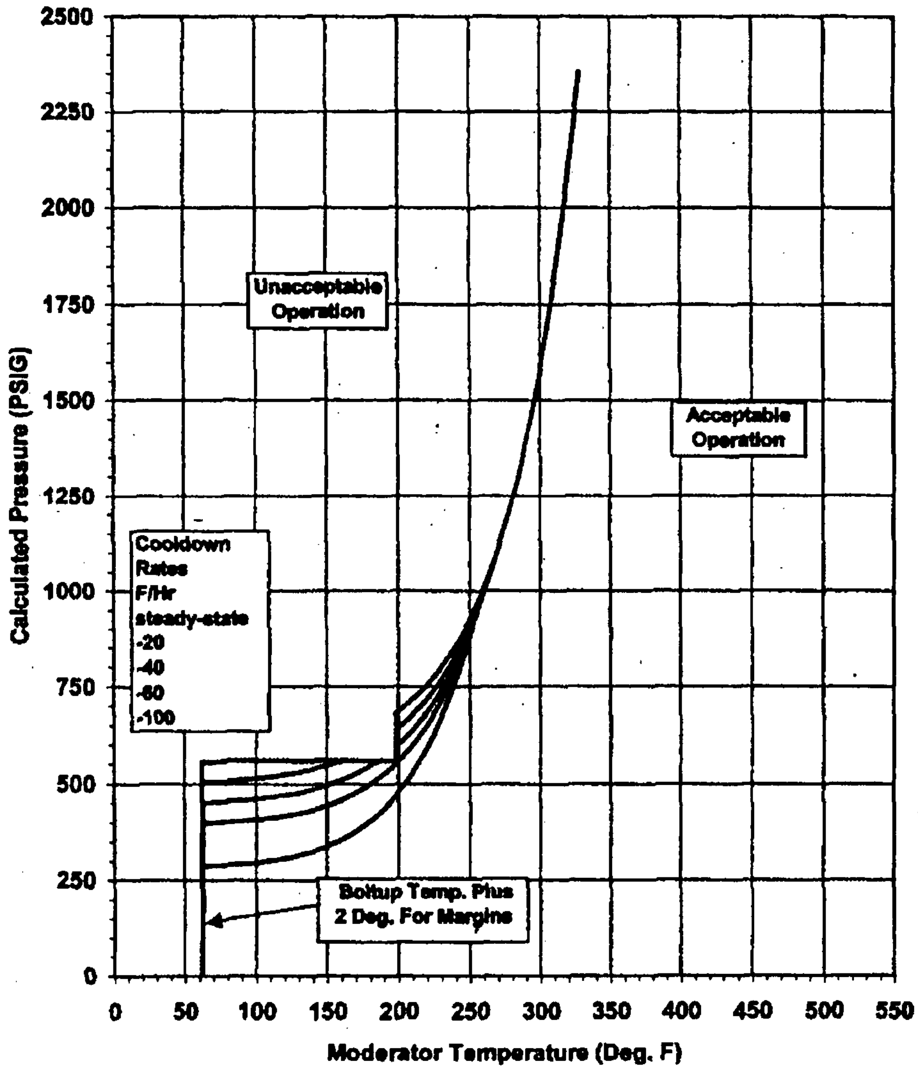

Figure 3.4-3 Salem Unit 1 Reactor Coolant System Cooldown Limitations Applicable for Cooldown Rates up to 100°F/HR for the Service Period up to 32 EFPY (with uncertainties for instrumentation errors)

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LIMITING CONDITION FOR OPERATION

3.4.9.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 200°F in any one hour period, and

c. A maximum spray water temperature differential of 320°F.

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the fracture toughness properties of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown. The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during auxiliary spray operation.

LIMITING CONDITION FOR OPERATION

3.4.9.3 At least one of the following overpressure protection systems shall be OPERABLE:

a. Two Pressurizer Overpressure Protection System relief valves (POPS) with a lift setting of less than or equal to 375 psig, or

b. A reactor coolant system vent of greater than or equal to 3.14 square inches.

APPLICABILITY: When the temperature of one or more of the RCS cold legs is less than or equal to 312°F, except when the reactor vessel head is removed.

ACTION:

a. With one POPS inoperable in MODE 4 and the temperature of one or more of the RCS cold legs is less than or equal to 312°F, either restore the inoperable POPS to OPERABLE status within 7 days or depressurize and vent the RCS through a 3.14 square inch vent(s) within the next 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

b. With one POPS inoperable in MODES 5 or 6 with the Reactor Vessel Head installed, restore the inoperable POPS to OPERABLE status within 24 hours, or complete depressurization and venting of the RCS through at least a 3.14 square inch vent(s) within the next 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

c. With both POPSs inoperable, depressurize and vent the RCS through a 3.14 square inch vent(s) within 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

d. In the event either the POPS or the RCS vent(s) are used to mitigate a RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the POPS or vent(s) on the transient and any corrective action necessary to prevent recurrence.

e. LCO 3.0.4.b is not applicable when entering MODE 4.

REACTOR COOLANT SYSTEM

OVERPRESSURE PROTECTION SYSTEMS

SURVEILLANCE REQUIREMENTS

4.4.9.3.1 Each POPS shall be demonstrated OPERABLE by:

a. Performance of a CHANNEL FUNCTIONAL TEST on the POPS actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the POPS is required OPERABLE, and at least once per 31 days thereafter when the POPS is required OPERABLE.

b. Performance of a CHANNEL CALIBRATION on the POPS actuation channel at least once per 18 months.

c. Verifying the POPS isolation valve is open at least once per 72 hours when the POPS is being used for overpressure protection.

d. Testing pursuant to Specification 4.0.5.

4.4.9.3.2 The RCS vent(s) shall be verified to be open at least once per 12 hours* when the vents(s) is being used for overpressure protection.

*Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

REACTOR COOLANT SYSTEM

3.4.10 STRUCTURAL INTEGRITY

ASME CODE CLASS 1, 2 and 3 COMPONENTS

LIMITING CONDITION FOR OPERATION

3.4.10.1 The structural integrity of ASME Code Class 1, 2 and 3 components shall be maintained in accordance with Specification 4.4.10.1.1.

APPLICABILITY: ALL MODES

ACTION:

a. With the structural integrity of any ASME Code Class 1 omponent(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant system temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

SURVEILLANCE REQUIREMENTS

4.4.10.1.1 The structural integrity of ASME Code Class 1, 2 and 3 components shall be demonstrated:

a. Per the requirements of Specification 4.0.5, and

b. Per the requirements of the augmented inservice inspection program specified in Specification 4.4.10.1.2.

In addition to the requirements of Specification 4.0.5, each Reactor Coolant Pump flywheel shall be inspected per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

4.4.10.1.2 Augmented Inservice Inspection Program for Steam Generator Channel Heads - The steam generator channel heads shall be ultrasonically inspected during each of the first three refueling outages using the same ultrasonic inspection procedures and equipment used to generate the baseline data. These inservice ultrasonic inspections shall verify that the cracks observed in the stainless steel cladding prior to operation have not propagated into the base material. The stainless steel clad surfaces of the steam generator channel heads shall also be visually inspected during the above outages. This may be accomplished by direct visual examination or by remote means such as television camera. If the visual examination, either direct or remote, reveals detectable cladding indications, a record shall be made by means of a video tape recording or photographs for comparison purposes.

SECTION 3/4.4.11
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3/4.4.12 HEAD VENTS

LIMITING CONDITION FOR OPERATION

3.4.12 Four reactor vessel head vent paths shall be operable with the vent paths closed. A vent path consists of at least two head vent valves in series, powered from vital sources, and associated flowpath.

APPLICABILITY: MODES 1, 2, 3 AND 4.

ACTION:

a. With one, two or three reactor vessel head vent path(s) inoperable, STARTUP and/or POWER OPERATION may continue provided the inoperable vent path(s) is maintained closed with the valve actuators key locked in the closed position; restore the inoperable vent path(s) to OPERABLE status within 30 days, or, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With four reactor vessel head vent paths inoperable; maintain the inoperable vent paths closed with power removed from the valve actuators of all the vent valves in the inoperable vent paths, and restore at least one of the vent paths to OPERABLE status within 72 hours or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.12 Reactor vessel head vent system vent paths shall be demonstrated OPERABLE at least once per 18 months by:

1. Verifying all manual isolation valves in each vent path are locked in the open position.

2. Cycling each valve in the vent paths through at least one complete cycle of full travel from the control room during COLD SHUTDOWN or REFUELING.

3. Verifying flow through the reactor vessel head vent system vent path during venting.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system accumulator shall be OPERABLE with:

a. The isolation valve open,

b. A contained volume of between 6,223 and 6,500 gallons of borated water,

c. A boron concentration of between 2,200 and 2,500 ppm, and,

d. A nitrogen cover-pressure of between 595.5 and 647.5 psig.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. With one accumulator inoperable, except as a result of a closed isolation valve or boron concentration outside the required limits, restore the inoperable accumulator to OPERABLE status within 24 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With one accumulator inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in HOT STANDBY within 24 hours and be in HOT SHUTDOWN within the next 12 hours.

c. With the boron concentration of one accumulator outside the required limits, restore the boron concentration to within the required limits within 72 hours or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than or equal to 1000 psig within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the water level and nitrogen cover-pressure in the tanks, and

2. Verifying that each accumulator isolation valve is open.

* Pressurizer Pressure above 1000 psig.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of ≥ 1% of tank volume by verifying the boron concentration of the accumulator solution.

c. At least once per 31 days when the RCS pressure is greater than 1000 psig by verifying that the power lockout switch is in lockout.

d.* At least once per 18 months by verifying that each accumulator isolation valve opens automatically upon receipt of a safety injection test signal.

* A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

EMERGENCY CORE COOLING SYSTEMS

ECCS SUBSYSTEMS - $T_{avg} \geq 350°F$

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of the following injection systems:

a. One OPERABLE centrifugal charging pump and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

   1. Discharging into each Reactor Coolant System (RCS) cold leg.

b. One OPERABLE safety injection pump and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

   1. Discharging into each RCS cold leg, and; upon manual initiation,

   2. Discharging into its two associated RCS hot legs.

c. One OPERABLE residual heat removal pump and associated residual heat removal heat exchanger and flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation and;

   1. Discharging into each RCS cold leg.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

c. With both ECCS subsystems inoperable for surveillance testing, restore at least one subsystem to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours and at least COLD SHUTDOWN within the subsequent 24 hours.

SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying that the following valves are in the indicated positions with power to the valve operators removed:

Valve Number	Valve Function	Valve Position
a. 1 SJ 69	a. RHR pump suction	a. open
b. 1 SJ 30	b. SI pump suction	b. open
c. 11 SJ 40	c. SI discharge to hot legs	c. closed
d. 12 SJ 40	d. SI discharge to hot legs	d. closed
e. 1 RH 26	e. RHR discharge to hot legs	e. closed
f. 11 SJ 49	f. RHR discharge to cold legs	f. open
g. 12 SJ 49	g. RHR discharge to cold legs	g. open
h. 1 CS 14#	h. Spray additive tank discharge	h. open
i. 1 SJ 135	i. SI discharge to cold legs	i. open
j. 1 SJ 67	j. SI recirc. line isolation	j. open
k. 1 SJ 68	k. SI recirc. line isolation	k. open
l. 11 SJ 44	l. Containment sump isolation valve	l. closed
m. 12 SJ 44	m. Containment sump isolation valve	m. closed

2. Verifying that the following valves are in the indicated positions:

Valve Number	Valve Function	Valve Position
a. 11 RH 19	a. RHR crosstie valve	a. open
b. 12 RH 19	b. RHR crosstie valve	b. open

b. At least once per 31 days by:

1. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

2. Verifying that the ECCS piping is full of water by venting the ECCS pump casings and accessible discharge piping high points.

If inoperable, the applicable Technical Specification is 3.6.2.2.

c. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

   1. For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

   2. At least once daily (24 hour consecutive period) the areas affected within containment by containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

d. At least once per 18 months by:

   1. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

e. At least once per 18 months, during shutdown, by:

   1.* Verifying that each automatic valve in the flow path actuates to its correct position on a safety injection test signal.

   2. Verifying that each of the following pumps start automatically upon receipt of a safety injection test signal:

      a) Centrifugal charging pump

      b) Safety injection pump

      c) Residual heat removal pump

* A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

f. By verifying that each of the following pumps develops the indicated Total Dynamic Head (TDH) when tested at the test flow point pursuant to Specification 4.0.5:

1. Centrifugal charging pump ≥ 2338 psi TDH
2. Safety Injection Pump ≥ 1369 psi TDH
3. Residual heat removal pump ≥ 165 psi TDH

g. By verifying the correct position of each of the following ECCS throttle valves:

1. Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE.
2. At least once per 18 months.

HPSI SYSTEM VALVE NUMBER	LPSI SYSTEM VALVE NUMBER
11 SJ 16	11 SJ 138
12 SJ 16	12 SJ 138
13 SJ 16	13 SJ 138
14 SJ 16	14 SJ 138
	11 SJ 143
	12 SJ 143
	13 SJ 143
	14 SJ 143

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1. For Safety Injection pumps, with a single pump running:

   a) The sum of the injection line flow rates, excluding the highest flow rate, is ≥ 453 gpm; and

   b) The total flow rate through all four injection lines is ≤ 647 gpm, and

   c) The difference between any pair of injection line flow rates is ≤ 12.0 gpm, and

   d) The total pump flow rate is ≤ 664 gpm in the cold leg alignment, and

   e) The total pump flow rate is ≤ 654 gpm in the hot leg alignment.

SURVEILLANCE REQUIREMENTS (Continued)

2. For Centrifugal Charging pumps, with a single pump running:

   a) The sum of the injection line flow rates, excluding the highest flow rate, is ≥ 306 gpm, and

   b) The total flow rate through all four injection lines is ≤ 444 gpm, and

   c) The difference between any pair of injection line flow rates is ≤ 10.5 gpm, and

   d) The total pump flow rate is ≤ 554 gpm.

i. The automatic interlock function of the RHR System shall be verified within the seven (7) days prior to placing the RHR System in service for cooling of the Reactor Coolant System. This shall be done by verifying with a test signal corresponding to a reactor coolant pressure of 375 psig or greater, that the 1RH1 and 1RH2 valves cannot be opened.

EMERGENCY CORE COOLING SYSTEMS

ECCS SUBSYSTEMS - Tavg <350°F

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE centrifugal charging pump# and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

 1. Discharging into each Reactor Coolant System (RCS) cold leg.

b. One OPERABLE residual heat removal pump and associated residual heat removal heat exchanger and flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation and;

 1. Discharging into each RCS cold leg, and; upon manual initiation,

 2. Discharging into two RCS hot legs.

APPLICABILITY: MODE 4.

ACTION:

a. With no ECCS subsystem OPERABLE because of the inoperability of either the centrifugal charging pump or the flow path from the refueling water storage tank, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 hours.

b. With no ECCS subsystem OPERABLE because of the inoperability of either the residual heat removal heat exchanger or residual heat removal pump, restore at least one ECCS subsystem to OPERABLE status or maintain the Reactor Coolant System T_{avg} less than 350°F by use of alternate heat removal methods.

c. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

d. LCO 3.0.4.b is not applicable to ECCS high head subsystem

A maximum of one safety injection pump or one centrifugal charging pump shall be OPERABLE in MODE 4 when the temperature of one or more of the RCS cold legs is less than or equal to 312°F, Mode 5, or Mode 6 when the head is on the reactor vessel.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE per applicable Surveillance Requirements of 4.5.2.

4.5.3.2 All safety injection pumps and centrifugal charging pumps, except the above required OPERABLE pump, shall be demonstrated to be inoperable at least once per 12 hours while in MODE 4 and the temperature of one or more of the RCS cold legs is less than or equal to 312°F, MODE 5, or MODE 6 when the head is on the reactor vessel by either of the following methods:

a. By verifying that the motor circuit breakers have been removed from their electrical power supply circuits or,

b. For verifying that the pump is in a recirculation flow path and that two independent means of preventing RCS injection are utilized.

EMERGENCY CORE COOLING SYSTEMS

SEAL INJECTION FLOW

LIMITING CONDITION FOR OPERATION

3.5.4 Reactor coolant pump seal injection flow shall be ≤40 gpm with centrifugal charging pump discharge header pressure ≥2430 psig and the charging flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3

ACTION:

With seal injection flow not within the limit, adjust manual seal injection throttle valves to give a flow within the limit with the charging pump discharge pressure ≥2430 psig and the charging flow control valve full open within 4 hours, or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 At least once per 31 days, verify manual seal injection throttle valves are adjusted to give a flow within the limit with centrifugal charging pump discharge header pressure ≥2430 psig, and the charging flow control valve full open.

The provisions of Specification 4.0.4 are not applicable for entry into Mode 3. This exemption is allowed for up to 4 hours after the Reactor Coolant System pressure stabilizes at 2235 ± 20 psig.

REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.5 The refueling water storage tank (RWST) shall be OPERABLE with:

a. A contained volume of between 364,500 and 400,000 gallons of borated water.

b. A boron concentration of between 2300 and 2500 ppm, and

c. A minimum water temperature of 35°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the refueling water storage tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.5 The RWST shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the water level in the tank, and

2. Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is < 35°F.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a1. At least once per 31 days by verifying that each containment manual valve or blind flange that is located outside containment and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls. Valves and blind flanges in high radiation areas may be verified by use of administrative controls.

a2. Prior to entering Mode 4 from Mode 5 if not performed within the last 92 days by verifying that each containment manual valve or blind flange that is located inside containment and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls. Valves and blind flanges in high radiation areas may be verified by use of administrative controls.

b. By verifying that each containment air lock is OPERABLE per Specification 3.6.1.3.

c. At least once per 12 hours by verifying that the surveillance requirements of 4.6.2.3.a are met for penetrations associated with the containment fan coil units.

d. At least once per 18 months by verifying that the surveillance requirements of 4.6.2.3.d are met for penetrations associated with the containment fan coil units.

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate (Type A test) in accordance with the Containment Leakage Rate Testing Program.

b. A combined leakage rate in accordance with the Containment Leakage Rate Testing Program for all penetrations and valves subject to Type B and C tests.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With either (a) the measured overall integrated containment leakage (Type A test) not in accordance with the Containment Leakage Rate Testing Program, or (b) with the measured combined leakage rate for all penetrations and valves subject to Types B and C tests not in accordance with the Containment Leakage Rate Testing Program, restore the leakage rate(s) to within the limit(s) prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated as follows:

a. Type A tests shall be in accordance with the Containment Leakage Rate Testing Program.

b. Type B and C tests shall be conducted in accordance with the Containment Leakage Rate Testing Program.

c. Air locks shall be tested and demonstrated OPERABLE in accordance with the Containment Leakage Rate Testing Program.

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CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and:

b. An overall air lock leakage rate in accordance with the Containment Leakage Rate Testing Program.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

Notes

(1) Entry and exit is permissible to perform repairs on the affected air lock components.

(2) Separate condition entry is allowed for each air lock.

(3) Required ACTIONS a.1, a.2, and a.3 are not applicable if both doors in the same air lock are inoperable and condition c. is entered.

(4) Required ACTIONS b.1, b.2, and b.3 are not applicable if both doors in the same air lock are inoperable and condition c. is entered.

(5) Enter applicable Conditions and required Actions of LCO 3.6.1, "Primary Containment," when air lock leakage results in exceeding the overall containment leakage rate.

a. One or more containment air locks with one containment airlock door inoperable:

1. Verify the OPERABLE door is closed in the affected air lock within 1 hour, and:

2. Lock the OPERABLE door closed in the affected air lock within 24 hours, and:

3. Verify the OPERABLE door is locked closed in the affected air lock once per 31 days. Entry and exit is permissible for 7 days (from initial LCO entry) under administrative controls if one door is inoperable in each air lock. Air lock doors in high radiation areas may be verified locked closed by administrative means.

b. One or more containment air locks with only the containment air lock interlock mechanism inoperable.

1. Verify an OPERABLE door is closed in the affected air lock within 1 hour, and:

2. Lock an OPERABLE door closed in the affected air lock within 24 hours, and:

3. Verify an OPERABLE door is locked closed in the affected air lock once per 31 days. Entry and exit of containment is permissible under the control of a dedicated individual for the duration of the entry to ensure only one door is open at a time. Air lock doors in high radiation areas may be verified locked closed by administrative means.

LIMITING CONDITION FOR OPERATIONS (Continued)

c. One or more containment air locks inoperable for reasons other than condition a. or b.

   1. Immediately initiate action to evaluate overall containment leakage per LCO 3.6.1, and:

   2. Verify that at least one door is closed in the affected air lock within 1 hour, and:

   3. Restore the air lock to OPERABLE status within 24 hours.

d. If the ACTIONS and associated completion times of a., b., or c. cannot be met, be in Hot Standby within 6 hours and in Cold Shutdown within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. By verifying seal leakage rate in accordance with the Containment Leakage Rate Testing program.

b. By conducting an overall air lock leakage test in accordance with the Containment Leakage Rate Testing Program.

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -1.5 and +0.3 psig.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

CONTAINMENT SYSTEMS

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall not exceed 120°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment average air temperature > 120°F, reduce the average air temperature to within the limit within 8 hours, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 Verify the Containment Average Air Temperature is within limit at least once per twenty four hours.

CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITIONS FOR OPERATION

3.6.1.6 The structural integrity of the containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.6. 1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the structural integrity of the containment not conforming to the above requirements, restore the structural integrity to within the limits prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.6.1 Containment Surfaces The structural integrity of the exposed accessible interior and exterior surfaces of the containment, including the liner plate, shall be determined in accordance with the Containment Leakage Rate Testing Program.

4.6.1.6.2 Reports Any abnormal degradation of the containment structure detected during the above required inspections shall be evaluated for reportability pursuant to 10CFR50.72 and 10CFR50.73. The evaluation shall be documented and shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective action taken.

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Note that the elements of TS 3.6.1.7 and 4.6.1.7 were relocated to TS 3/4.6.3.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

CONTAINMENT SPRAY SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.1 Two independent containment spray systems shall be OPERABLE with each spray system capable of taking suction from the RWST and transferring suction to the RHR pump discharge.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one containment spray system inoperable, restore the inoperable spray system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the inoperable spray system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.1 Each containment spray system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying, that on recirculation flow, each pump develops a differential pressure of greater than or equal to 204 psid when tested pursuant to Specification 4.0.5.

c. At least once per 18 months during shutdown, by:

   1. Verifying that each automatic valve in the flow path actuates to its correct position on a Containment High-High pressure test signal.

   2. Verifying that each spray pump starts automatically on a Containment High-High pressure test signal.

d. Following activities that could result in nozzle blockage, either evaluate the work performed to determine the impact to the containment spray system, or perform an air or smoke flow test through each spray header and verifying each spray nozzle is unobstructed.

SPRAY ADDITIVE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The spray additive system shall be OPERABLE with:

a. A spray additive tank containing a volume of between 2568 and 4000 gallons of between 30 and 32 percent by weight NaOH solution, and

b. Two spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a containment spray system pump flow.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the spray additive system inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the spray additive system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The spray additive system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. It least once per 6 months by:

1. Verifying the solution level in the tank, and

2. Verifying the concentration of the NaOH solution by chemical analysis.

c. At least once per 18 months during shutdown, by verifying that each automatic valve in the flow path actuates to its correct position on a Containment High-High pressure test signal.

d. At least once per 5 years by:

1. Verifying a NaOH solution flow rate of 12 $\pm$ 3 gpm from the spray additive tank through sample valve 1CS61 with the spray additive tank at 2.5 $\pm$ 0.5 psig and

SPRAY ADDITIVE SYSTEM

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the spray additive tank eductor flow will be 35 ± 3.5 gpm to each containment spray system. Testing may be performed by measuring the flow of borated water from the RWST through the installed 2" test line and Valve CS31; using this test line up with the spray pump operating in the recirculation mode and the RWST level at 41 feet ± 0.5 feet, the measured flow shall be 57 gpm ± 5.7 gpm.

CONTAINMENT COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.3 Five containment cooling fans shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one or two of the above required containment cooling fans inoperable, restore the inoperable cooling fan(s) to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With three or more of the above required containment cooling fans inoperable, restore at least three cooling fans to OPERABLE status within 1 hour or be in at least HOT STANDBY WITHIN the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore the remaining inoperable cooling fans to OPERABLE status within 7 days of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 Each containment cooling fan shall be demonstrated OPERABLE:

SURVEILLANCE REQUIREMENTS (Continued)

a. At least once per 12 hours by:

1. Verifying the water level in each service water accumulator vessel is greater than or equal to 226 inches and less than or equal to 252 inches.

2. Verifying the temperature in each service water accumulator vessel is greater than or equal to 55°F and less than or equal to 95°F.

3. Verifying the nitrogen cover pressure in each service water accumulator vessel is greater than or equal to 135 psig and less than or equal to 160 psig.

b. At least once per 31 days by:

1. Starting (unless already operating) each fan from the control room in low speed.

2. Verifying that each fan operates for at least 15 minutes in low speed.

3. Verifying a cooling water flow rate of greater than or equal to 2550 gpm to each cooler.

c. At least once per 18 months by verifying that on a safety injection test signal:

1. Each fan starts automatically in low speed.

2. The automatic valves and dampers actuate to their correct positions and that the cooling water flow rate to each cooler is greater than or equal to 2550 gpm.

d. At least once per 18 months by verifying that on a loss of offsite power test signal, each service water accumulator vessel discharge valve response time is within limits.

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3.1 Each containment isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

NOTE 1

Penetration flow paths, except for the containment purge valves, may be unisolated intermittently under administrative controls.

Note 2

A containment purge valve is not a required containment isolation valve when its flow path is isolated with a testable blind flange tested in accordance with SR 4.6.1.2.b. The *required* containment purge supply and exhaust isolation valves shall be closed. (Valves immobilized in shut position with control air to valve operators isolated and tagged out of service).

NOTE 3

The containment pressure-vacuum relief isolation valves may be opened on an intermittent basis, under administrative control, as necessary to satisfy the requirement of Specification 3.6.1.4.

1. With one or more of the isolation valve(s) inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and either:

   a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

   b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

   c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or

   d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2. With one required containment purge supply and/or exhaust isolation valve open, close the open valve(s) within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1.1 DELETED

SURVEILLANCE REQUIREMENTS (Continued)

4.6.3.1.2 Each containment isolation valve shall be demonstrated OPERABLE during the COLD SHUTDOWN or REFUELING MODE at least once per 18 months by:

a. Verifying that on a Phase A containment isolation test signal, each Phase A isolation valve actuates to its isolation position.

b. Verifying that on a Phase B containment isolation test signal, each Phase B isolation valve actuates to its isolation position.

c. Not used.

d. Verifying that on a Containment Purge and Pressure-Vacuum Relief isolation test signal, each required Purge and each Pressure-Vacuum Relief valve actuates to its isolation position.

e. Verifying that the Containment Pressure-Vacuum Relief Isolation valves are limited to ≤ 60%opening angle.

4.6.3.1.3 At least once per 18 months, verify that on a main steam isolation test signal, each main steam isolation valve actuates to its isolation position.

4.6.3.1.4 The isolation time of each power operated or automatic containment isolation valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.3.1.5 Each required containment purge isolation valve shall be demonstrated OPERABLE within 24 hours after each closing of the valve, except when the valve is being used for multiple cyclings, then at least once per 72 hours, by verifying that when the measured leakage rate is added to the leakage rates determined pursuant to Specification 4.6.1.2.b for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60La.

4.6.3.1.6 A pressure drop test to identify excessive degradation of resilient valve seals shall be conducted on the:

a. Required Containment Purge Supply and Exhaust Isolation Valves at least once per 6 months.

b. Deleted.

4.6.3.1.7 The required containment purge supply and exhaust isolation valves shall be determined closed at least once per 31 days.

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3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves (MSSVs) associated with each steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one or two main steam line code safety valves inoperable in one or more steam generators, operation in Modes 1, 2 and 3 may proceed provided, that within 4 hours, either the inoperable valve is restored to OPERABLE status or reduce power to less than or equal to the applicable percent of RATED THERMAL POWER per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With three main steam line code safety valves inoperable in one or more steam generators, operation in Modes 1, 2 and 3 may proceed provided, that within 4 hours, either the inoperable valves are restored to OPERABLE status or reduce power to less than or equal to the applicable percent of RATED THERMAL POWER per Table 3.7-1 and within 36 hours, reduce the Power Range Neutron Flux High trip setpoint to less than or equal to the RATED THERMAL POWER per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify each required MSSV lift setpoint per Table 4.7-1. No additional Surveillance Requirements other than those required by Specification 4.0.5.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER
WITH INOPERABLE STEAM LINE SAFETY VALVES

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Power* (Percent of RATED THERMAL POWER)
1	87
2	59
3	39

*The values do not provide any allowance for calorimetric error.

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TABLE 4.7-1

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER	Loop A	Loop B	Loop C	Loop D	LIFT SETTING (± 3%)*	ORIFICE SIZE (sq. inches)
a.	11MS11	12MS11	13MS11	14MS11	1125 psig	16.0
b.	11MS12	12MS12	13MS12	14MS12	1120 psig	16.0
c.	11MS13	12MS13	13MS13	14MS13	1110 psig	16.0
d.	11MS14	12MS14	13MS14	14MS14	1100 psig	16.0
e.	11MS15	12MS15	13MS15	14MS15	1070 psig	16.0

*Following testing the lift setting shall be reset to within ± 1%.

PLANT SYSTEMS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated manual activation switches in the control room and flow paths shall be OPERABLE with:

a. Two feedwater pumps, each capable of being powered from separate vital busses, and

b. One feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective action to restore at least one auxiliary feedwater pump to OPERABLE status as soon as possible.

d. LCO 3.0.4.b is not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying that each non-automatic valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

2. Verify the manual maintenance valves in the flow path to each steam generator are locked open.

SURVEILLANCE REQUIREMENTS (continued)

b. At least once per 92 days on a STAGGERED TEST BASIS by:

1. Verify that the developed head of each motor driven pump at the flow test point is greater than or equal to the required developed head.

2. Verify that the developed head of the steam driven pump at the flow test point is greater than or equal to the required developed head when the steam generator pressure is >680 psig. The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 24 hours after secondary side pressure is greater than 680 psig.

c. At least once per 18 months by:

1. Verifying that each auxiliary feedwater automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

2. Verifying that each auxiliary feedwater pump starts automatically on an actual or simulated actuation signal.

The provisions of Specification 4.0.4 are not applicable to the turbine driven auxiliary feedwater pump provided the surveillance is performed within 24 hours after the secondary steam generator pressure is greater than 680 psig.

AUXILIARY FEED STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The auxiliary feed storage tank (AFST) shall be OPERABLE with a minimum contained volume of 200,000 gallons of water.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the auxiliary feed storage tank inoperable, within 4 hours either:

a. Restore the AFST to OPERABLE status or be in HOT SHUTDOWN within the next 12 hours, or

b. Demonstrate the OPERABILITY of a demineralized water or a fire protection/domestic water storage tank as a backup supply to the auxiliary feedwater pumps and restore the auxiliary feed storage tank to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3.1 The auxiliary feed storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level is within its limits when the tank is the supply source for the auxiliary feedwater pumps.

4.7.1.3.2 A demineralized water storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the tank contains $\geq$ 200,000 gallons of water and by verifying proper alignment of valves for taking suction from this tank when it is the supply source for the auxiliary feedwater pumps.

4.7.1.3.3 A fire protection/domestic water storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the tank contains $\geq$ 200,000 gallons of water and by verifying proper alignment of valves for taking suction from this tank when it is the supply source for the auxiliary feedwater pumps.

PLANT SYSTEMS

ACTIVITY

LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the secondary coolant system shall be $\leq$0.10 μCi/gram DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the specific activity of the secondary coolant system > 0.10 μCi/gram DOSE EQUIVALENT I-131, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the secondary coolant system shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-2.

TABLE 4.7-2

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY
SAMPLE AND ANALYSIS PROGRAM

	TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY
1.	Gross Activity Determination	At least once per 72 hours
2.	Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	a) 1 per 31 days, whenever the gross activity determination indicates iodine concentrations greater than 10% of the allowable limit. b) 1 per 6 months, whenever the gross activity determination indicates iodine concentrations below 10% of the allowable limit.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.5 Each main steam line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

MODES 1 - With one main steam line isolation valve inoperable, POWER OPERATION may continue provided the inoperable valve is either restored to OPERABLE status or closed within 4 hours;

otherwise, be in MODE 2 within the next 6 hours.

MODES 2 and 3 - With one or more main steam line isolation valve(s) inoperable, subsequent operation in MODES 2 or 3 may proceed provided;

a. The isolation valve(s) is (are) maintained closed, and

b. The isolation valve(s) is (are) verified closed once per 7 days.

Otherwise, be in MODE 3, HOT STANDBY, within the next 6 hours, and MODE 4, HOT SHUTDOWN, within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.5 Each main steam line isolation valve shall be demonstrated OPERABLE by verifying full closure within 5 seconds when tested pursuant to Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable.

LIMITING CONDITION FOR OPERATION

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PLANT SYSTEMS

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

LIMITING CONDITION FOR OPERATION

3.7.2.1 The temperatures of both the primary and secondary coolants in the steam generators shall be > 70°F when the pressure of either coolant in the steam generator is > 200 psig.

APPLICABILITY: At all times.

ACTION:

With the requirements of the above specification not satisfied:

a. Reduce the steam generator pressure of the applicable side to ≤ 200 psig within 30 minutes, and

b. Perform an engineering evaluation to determine the effect of the overpressurization on the structural integrity of the steam generator. Determine that the steam generator remains acceptable for continued operation prior to increasing its temperatures above 200°F.

SURVEILLANCE REQUIREMENTS

4.7.2.1 The pressure in each side of the steam generator shall be determined to be < 200 psig at least once per hour when the temperature of either the primary or secondary coolant is < 70°F.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3.1 At least two independent component cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one component cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3.1 At least two component cooling water loops shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

3/4.7.4 SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two independent service water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one service water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours * or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two service water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety related equipment actuates to its correct position on Safeguards Initiation signal.

* Operation with only the 11 service water loop OPERABLE may continue for up to 10 days. This note is applicable for one time use during Salem Unit No.1 Cycle 15.

3/4.7.5 FLOOD PROTECTION

LIMITING CONDITION FOR OPERATION

3.7.5.1 Flood protection shall be provided for all safety related systems, components and structures when the water level of the Delaware River exceeds 10.5' Mean Sea Level USGS datum, at the service water intake structure.

APPLICABILITY: At all times.

ACTION:

a. With the water level at the service water intake structure above elevation 10.5' Mean Sea Level USGS datum, close all watertight doors within 2 hours.

b. With the water level at the service water intake structure above elevation 11.5' Mean Sea Level USGS datum, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.5.1 The water level at the service water intake structure shall be determined to be within the limits by:

a. Measurement at least once per 24 hours when the water level is below elevation 10.5' Mean Sea Level USGS datum, and

b. Measurement at least once per 2 hours when the water level is equal to or above elevation 10.5' Mean Sea Level USGS datum.

3/4.7.6 CONTROL ROOM EMERGENCY AIR CONDITIONING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 The common control room emergency air conditioning system (CREACS)* shall be OPERABLE with:

a. Two independent air conditioning filtration trains (one from each unit) consisting of:

1. Two fans and associated outlet dampers,
2. One cooling coil,
3. One charcoal adsorber and HEPA filter array,
4. Return air isolation damper.

b. All other automatic dampers required for operation in the pressurization or recirculation modes.

c. The control room envelope intact.

APPLICABILITY: ALL MODES and during movement of irradiated fuel assemblies.

ACTION: MODES 1, 2, 3, and 4

a. With one filtration train inoperable, align CREACS for single filtration train operation within 4 hours, and restore the inoperable filtration train to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With CREACS aligned for single filtration train operation and with one of the two remaining fans or associated outlet damper inoperable, restore the inoperable fan or damper to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With the Control Room Envelope inoperable, restore the Control Room Envelope to OPERABLE status within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With one or both series isolation damper(s) on a normal Control Area Air Conditioning System (CAACS) outside air intake or exhaust duct inoperable, close the affected duct within 4 hours by use of at least one isolation damper secured in the closed position or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. (Refer to ACTION 25 of Table 3.3-6.)

* The CREACS is a shared system with Salem Unit 2

e. With one or both isolation damper(s) on an outside emergency air conditioning air intake duct inoperable, close the affected duct within 4 hours by use of at least one isolation damper secured in the closed position and restore the damper(s) to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

f. With any isolation damper between the normal CAACS and the CREACS inoperable, secure the damper in the closed position within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

MODES 5 and 6 or during movement of irradiated fuel assemblies

a. With one filtration train inoperable, align CREACS for single filtration train operation within 4 hours, or suspend movement of irradiated fuel assemblies.

b. With CREACS aligned for single filtration train operation with one of the two remaining fans or associated outlet damper inoperable, restore the fan or damper to OPERABLE status within 72 hours, or suspend movement of irradiated fuel assemblies.

c. With two filtration trains inoperable, immediately suspend movement of irradiated fuel assemblies.

d. With the Control Room Envelope inoperable, immediately suspend movement of irradiated fuel assemblies.

e. With one or both series isolation damper(s) on a normal CAACS outside air intake or exhaust duct inoperable, immediately suspend movement of irradiated fuel assemblies until the affected duct is closed by use of at least one isolation damper secured in the closed position. (Refer to ACTION 25 of Table 3.3-6.)

f. With one or both series isolation damper(s) on an outside emergency air conditioning air intake duct inoperable, immediately suspend movement of irradiated fuel assemblies until the affected duct is closed by use of at least one isolation damper secured in the closed position. To resume movement of irradiated fuel assemblies, at least one emergency air intake duct must be operable on each unit.

g. With any isolation damper between the CAACS and the CREACS inoperable, immediately suspend movement of irradiated fuel assemblies until the damper is closed and secured in the closed position.

SURVEILLANCE REQUIREMENTS

4.7.6.1 Each control room emergency air conditioning system filtration train shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating flow through the HEPA filter and charcoal adsorber train(s) and verifying that the train(s) operates with each fan operating for at least 15 minutes.

b. At least once per 18 months or prior to return to service (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the system, by:

   1. Verifying that the charcoal adsorbers remove ≥99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

   2. Verifying that the HEPA filter banks remove ≥99% of the DOP when they are tested in-place while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

   3. Verifying within 31 days after removal from the CREACS unit, that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal from the CREACS unit, that a laboratory analysis of a representative carbon sample, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows a methyl iodide penetration less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

d. At least once per 18 months by:

   1. Verifying that the pressure drop across the combined HEPA filter and charcoal adsorber bank is ≤ 3.5 inches water gauge while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

   2.* Verifying that on a safety injection test signal or control room intake high radiation test signal, the system automatically actuates in the pressurization mode by opening the outside air supply and diverting air flow through the HEPA filter and charcoal adsorber bank.

   3. Verifying that the system can maintain the control room at a positive pressure ≥ 1/8" water gauge relative to the adjacent areas during system operation with makeup air being supplied through the HEPA filters and charcoal adsorbers at the design makeup flow rate of ≤ 2200 cfm.

* A one time extension to this surveillance requirement which is satisfied by performance of the Manual SI test is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

SURVEILLANCE REQUIREMENTS (Continued)

4. Verifying that on a manual actuation signal, the system will actuate to the required pressurization or recirculation operating mode.

5. Verify each CREACS train has the capability to remove the assumed heat load.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place while operating the filter system at a flow rate of 8000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorbers bank by verifying that the charcoal adsorbers remove ≥ 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the filter system at a flow rate of 8000 cfm ± 10%.

3/4.7.7 AUXILIARY BUILDING VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.1 At least two supply fans, and three exhaust fans shall be OPERABLE (*) to maintain the Auxiliary Building at slightly negative pressure.

---------------------------------NOTE---------------------------------
The intermittent opening of the Auxiliary Building pressure boundary causing a loss of negative pressure may be performed under administrative controls.

APPLICABILITY: At all times

ACTION:

Modes 1 thru 4

a) With one supply fan and/or one exhaust fan inoperable, restore the fan(s) to OPERABLE status within 14 days or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b) With two supply and/or two exhaust fans inoperable restore at least one inoperable supply and two exhaust fans to operable status within 24 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c) With the Auxiliary Building pressure not maintained slightly negative, restore the Auxiliary Building to slightly negative pressure within the next 4 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

During CORE ALTERATIONS

d) With the Auxiliary Building pressure not maintained slightly negative, restore the Auxiliary Building to slightly negative pressure within the next 4 hours or suspend all operations involving CORE ALTERATIONS.

At all times

e) With the Auxiliary Building pressure not maintained slightly negative, suspend all operations involving radioactive gaseous releases via the Auxiliary Building immediately.

(*) One of the supply fans may be considered OPERABLE with its auto start circuit administratively controlled (removed from service) to prevent more than one supply fan from operating at any time.

4.7.7.1 The above required Auxiliary Building Ventilation System shall be demonstrated OPERABLE by:

a. At least once per 12 hours by verifying negative pressure in the Auxiliary Building.

b. At least once per 31 days by starting each fan, from the control room, and verifying that each fan operates for at least 15 minutes.

c. At least once per 18 months by verifying that the System starts following a Safety Injection Test Signal.

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PLANT SYSTEMS

3/4.7.8 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.8.1 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of ≥ 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. Each sealed source with removable contamination in excess of the above limits shall be immediately withdrawn from use and:

1. Either decontaminated and repaired, or

2. Disposed of in accordance with Commission Regulations.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.8.1.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.8.1.2 Test Frequencies - Each category of sealed sources shall be tested at the frequency described below.

a. Sources in use (excluding startup sources and fission detectors previously subjected to core flux) - At least once per six months for all sealed sources containing radioactive materials.

SURVEILLANCE REQUIREMENTS (Continued)

1. With a half-life greater than 30 days (excluding Hydrogen 3), and

2. In any form other than gas.

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources and fission detectors transferred without a certificate indicating the last test data shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux and following repair or maintenance to the source or detector.

4.7.8.1.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of $\geq$ 0.005 microcuries of removable contamination.

3/4.7.9 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.9 All snubbers shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4. (MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES).

ACTION:

With one or more snubbers inoperable, within 72 hours, replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.9c on the supported component or declare the supported system inoperable and follow appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.9 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Visual Inspection

All snubbers shall be categorized into two groups: those accessible and those inaccessible during reactor operation. The visual inspection interval for each category of snubbers shall be determined based upon the criteria provided in Table 4.7-3.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are secure, and (3) in those locations where snubber movement can be manually induced without disconnnecting the snubber, that the snubber has freedom of movement and is not frozen up. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, providing that (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specification 4.7.9d or 4.7.9e as applicable. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable and cannot be determined OPERABLE via functional testing for the purpose of establishing the next visual inspection interval. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

c. Functional Tests

At least once per 18 months during shutdown, a representative sample of 10% of the total of each type of snubber in use in the plant shall be functionally tested either in place or in a bench test. For each type of snubber that does not meet the functional test acceptance criteria of Specification 4.7.9d or 4.7.9e, an additional 10% of that type of snubber shall be functionally tested.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle

2. Snubbers within five feet of heavy equipment (valve, pump, turbine, motor, etc.)

3. Snubbers within ten feet of the discharge from a safety relief valve

SURVEILLANCE REQUIREMENTS (Continued)

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber (if it is repaired and installed in another position) and the spare snubber shall be retested. Test results of these snubbers may not be included for the re-sampling.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

For the snubber(s) found inoperable, an engineering evaluation shall be performed on the components which are supported by the snubber(s). The purpose of this engineering evaluation shall be to determine if the components supported by the snubber(s) were adversely affected by the inoperability of the snubber(s) in order to ensure that the supported component remains capable of meeting the designed service.

d. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

e. Mechanical Snubbers Functional Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

SURVEILLANCE REQUIREMENTS (Continued)

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

f. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.m.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records.

TABLE 4.7-3

SNUBBER VISUAL INSPECTION INTERVAL

Population[1,2] /Category	Number of Unacceptable Snubbers: Column A[3,6] Extend Interval	Column B[4,6] Repeat Interval	Column C[5,6] Reduce Interval
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8

Notes:

1. The next visual inspection interval for the population of a snubber category shall be determined based upon the most recent inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. This decision shall be made and documented before any inspection and used as the basis upon which to determine the next inspection interval for that category.

2. Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Where the limit for unacceptable snubbers in Columns A, B, or C is determined by interpolation and includes a fractional value, the limit may be reduced to the next lower integer.

3. If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

4. If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the current interval.

5. If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the current interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is:

$$I_1 = I_0 - I_0 * {}^1/_3 * \frac{U - B}{C - B}$$

where:

I_1	=	next inspection interval
I_0	=	current inspection interval
U	=	number of unacceptable snubbers found during the previous inspection interval
B	=	number in Column B
C	=	number in Column C

6. The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

3/4.7.10 CHILLED WATER SYSTEM - AUXILIARY BUILDING SUBSYSTEM

LIMITING CONDITION FOR OPERATION

3.7.10 The chilled water system loop which services the safety-related loads in the Auxiliary Building shall be OPERABLE with:

a. Three OPERABLE chillers

b. Two OPERABLE chilled water pumps

APPLICABILITY: ALL MODES and during movement of irradiated fuel assemblies.

ACTION: MODES 1, 2, 3, and 4

a. With one chiller inoperable:

1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

2. Restore the chiller to OPERABLE status within 14 days or;

3. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With two chillers inoperable:

1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

2. Align the control room emergency air conditioning system (CREACs) for single filtration operation using the Salem Unit 2 train within 4 hours and;

3. Restore at least one chiller to OPERABLE status within 72 hours or;

4. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one chilled water pump inoperable, restore the chilled water pump to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

LIMITING CONDITION FOR OPERATION

ACTION: MODES 5 and 6 or during movement of irradiated fuel assemblies. *

a. With one chiller inoperable:

   1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

   2. Restore the chiller to OPERABLE status within 14 days or;

   3. Suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

b. With two chillers inoperable:

   1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

   2. Align the control room emergency air conditioning system (CREACs) for single filtration operation using the Salem Unit 2 train within 4 hours and;

   3. Restore at least one chiller to OPERABLE status within 72 hours or;

   4. Suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

c. With one chilled water pump inoperable, restore the chilled water pump to OPERABLE status within 7 days or suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.7.10 The chilled water loop which services the safety-related loads in the Auxiliary Building shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each manual valve in the chilled water system flow path servicing safety related components that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. ** At least once per 18 months, by verifying that each automatic valve actuates to its correct position on a Safeguards Initiation signal.

c. At least once per 92 days by verifying that each chiller starts and runs.

* During Modes 5 and 6 and during movement of irradiated fuel assemblies, chilled water components are not considered to be inoperable solely on the basis that the backup emergency power source, diesel generator, is inoperable.

**A one time extension to this surveillance requirement for performance of relay time response and sequence testing of the safeguard equipment control (SEC) system, which partially satisfies the surveillance requirement, is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.7.11 The fuel storage pool boron concentration shall be ≥ 800 ppm.

APPLICABILITY: When fuel assemblies are stored in the fuel storage pool and a fuel storage pool verification has not been performed since the last movement of fuel assemblies in the fuel storage pool.

ACTION:

With fuel storage pool boron concentration not within limit:

a. Immediately suspend movement of fuel assemblies in the fuel storage pool and

b. Initiate action to:

1. immediately restore fuel storage pool boron concentration to within limit or

2. immediately perform a fuel storage pool verification.

c. LCO 3.0.3 is not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11 Verify the fuel storage pool boron concentration is within limit every 7 days.

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL

LIMITING CONDITION FOR OPERATION

3.7.12 The combination of initial enrichment, burnup, and Integral Fuel Burnable Absorber (IFBA) of each fuel assembly stored in Region 1 or Region 2, shall be within the acceptable limits described in the surveillance requirements below.

APPLICABILITY: When any fuel assembly is stored in Region 1 or Region 2 of the spent fuel storage pool.
ACTION:

If the requirements of the LCO are not met:

a. Immediately verify the fuel storage boron concentration meets the requirements of TS 3.7.11 and

b. Immediately initiate action to move the non-complying fuel assembly to a location that complies with the surveillance requirements.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.12.1 Prior to storing fuel assemblies in Region 1, verify by administrative means that the fuel assemblies meet one of the following storage constraints:

a. Unirradiated fuel assemblies with a maximum enrichment of 4.25 wt% U-235 have unrestricted storage.

b. Unirradiated fuel assemblies with enrichments greater than 4.25 wt% U-235 and less than or equal to 5.0 wt% U-235, that do not contain IFBA pins, may only be stored in the peripheral cells facing the concrete wall.

c. Unirradiated fuel assemblies with enrichments (E) greater than 4.25 wt% U-235 and less than or equal to 5.0 wt% U-235, which contain a minimum number of IFBA pins have unrestricted storage. This minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold-down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5x), determined by the equation below:

$$N = 42.67\ (E - 4.25)$$

d. Irradiated fuel assemblies with enrichments (E) greater than 4.25 wt% U-235 and less than or equal to 5.0 wt%, that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -26.212 + 6.1677E$$

4.7.12.2 Prior to storing fuel assemblies in Region 2, verify by administrative means that the fuel assemblies meet one of the following storage constraints:

a. Unirradiated fuel assemblies with a maximum enrichment of 5.0 wt% U-235 may be stored in a checkerboard pattern with intermediate cells containing only water or non-fissile bearing material.

b. Unirradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 may be stored in the central cell of any 3x3 array of cells provided the surrounding eight cells are empty or contain fuel assemblies that have attained the minimum burnup (BU) as determined by the equation below.

$$BU\ (MWD/kg\ U) = -15.48 + 17.80E - 0.7038E^2$$

In this configuration, none of the nine cells in any 3x3 array shall be common to cells in any other similar 3x3 array. Along the rack periphery, the concrete wall is equivalent to 3 outer cells in a 3x3 array.

c. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -32.06 + 25.21E - 3.723E^2 + 0.3535E^3$$

d. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 that have attained the minimum burnup (BU) as determined by the equation below, may be stored in a peripheral cell facing the concrete wall.

$$BU\ (MWD/kg\ U) = -25.56 + 15.14E - 0.602E^2$$

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent A.C. circuits between the offsite transmission network and the onsite Class 1E distribution system (vital bus system), and

b. Three separate and independent diesel generators with:

   1. Separate day tanks containing a minimum volume of 130 gallons of fuel, and

   2. A common fuel storage system consisting of two storage tanks, each containing a minimum volume of 23,000 gallons of fuel, and two fuel transfer pumps.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With an independent A.C. circuit of the above required A.C. electrical power sources inoperable:

   1. Demonstrate the OPERABILITY of the remaining independent A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; and

   2. Within 24 hours, declare required systems or components with no offsite power available inoperable when a redundant required system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

   3. Restore the inoperable independent A.C. circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of the above required A.C. electrical power sources inoperable:

   1. Demonstrate the OPERABILITY of the independent A.C. circuits by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and

   2. Within 4 hours, declare required systems or components supported by the inoperable diesel generator inoperable when a required redundant system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

ACTION (Continued)

3. Determine the two remaining OPERABLE diesel generators are not inoperable due to common cause failure or perform Surveillance Requirement 4.8.1.1.2.a.2 within 24 hours. If the diesel generator is inoperable for preventive maintenance, the two remaining OPERABLE diesel generators need not be tested nor the OPERABILITY evaluated; and

4. In any case, restore the inoperable diesel generator to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one independent A.C. circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining independent A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; demonstrate the OPERABILITY of the remaining OPERABLE diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.2 within 8 hours; restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore at least two independent A.C. circuits and three diesel generators to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With two of the above required independent A.C. circuits inoperable:

1. Demonstrate the OPERABILITY of three diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.2 within 8 hours, unless the diesel generators are already operating; and

2. Within 12 hours, declare required systems or components supported by the inoperable offsite circuits inoperable when a required redundant system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

3. Restore at least one of the inoperable independent A.C. circuits to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours; and

4. With only one of the independent A.C. circuits OPERABLE, restore the other independent A.C. circuit to OPERABLE status within 72 hours from time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION (Continued)

e. With two or more of the above required diesel generators inoperable, demonstrate the OPERABILITY of two independent A.C. circuits by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; restore at least two of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore three diesel generators to OPERABLE status within 72 hours from time of initial loss or be in least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

f. With one of the above required fuel transfer pumps inoperable, either restore it to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

g. With one of the above required fuel storage tanks inoperable, either restore it to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

h. LCO 3.0.4.b is not applicable to DGs.

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SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Two physically independent A.C. circuits between the offsite transmission network and the onsite Class 1E distribution system (vital bus system) shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring (manually and automatically) vital bus supply from one 13/4 kv transformer to the other 13/4 kv transformer.

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by:

   1. Verifying the fuel level in its day tank.

   2. Verifying the diesel generator starts from standby conditions* and achieves $\geq$ 3910 volts and $\geq$ 58.8 Hz in $\leq$ 13 seconds, and subsequently achieves steady state voltage of $\geq$ 3910 and $\leq$ 4400 volts and frequency of 60 $\pm$ 1.2 Hz.

      Subsequently, verifying the generator is synchronized with voltage maintained $\geq$ 3910 and $\leq$ 4580 volts, gradually loaded to 2340-2600 kw**, and operates at a load of 2340-2600 kw for greater than or equal to 60 minutes.

   3. Verifying the diesel generator is aligned to provide standby power to the associated vital bus.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to one hour by checking for and removing accumulated water from the day tanks.

c. At least once per 6 months by verifying the diesel generator starts from standby conditions* and achieves $\geq$ 3910 volts and $\geq$ 58.8 Hz in $\leq$ 13 seconds, and subsequently achieves steady state voltage of $\geq$ 3910 and $\leq$ 4400 volts and frequency of 60 $\pm$ 1.2 Hz.

   The generator shall be synchronized to its emergency bus with voltage maintained $\geq$ 3910 and $\leq$ 4580 volts, loaded to 2340-2600** kw in less than or equal to 60 seconds, and operate at a load of 2340-2600 kw for at least 60 minutes.

   This test, if it is performed so it coincides with the testing required by Surveillance Requirement 4.8.1.1.2.a.2, may also serve to concurrently meet those requirements.

d. At least once per 18 months during shutdown by:

1. DELETED

2. Verifying that, on rejection of a load greater than or equal to 820 kw, the voltage and frequency are restored to ≥ 3910 and ≤ 4400 volts and 60 ± 1.2 Hz within 4 seconds, and subsequently achieves a steady state frequency of ≥ 58.8 and ≤ 60.5 Hz.

3. Simulating a loss of offsite power by itself, and:

   a) Verifying de-energization of the vital bus and load shedding from the vital bus.

   b) Verifying the diesel starts on the auto-start signal*, energizes the vital bus with permanently connected loads within 13 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization of these loads, the steady state voltage and frequency of the vital bus shall be maintained at ≥ 3910 and ≤ 4400 volts and ≥ 58.8 and ≤ 60.5 Hz during this test.

4. Verifying that on an ESF actuation test signal without loss of offsite power the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes*. The diesel generator shall achieve ≥ 3910 volts and ≥ 58.8 Hz in ≤ 13 seconds, and subsequently achieves steady state voltage of ≥ 3910 and ≤ 4400 volts and frequency of ≥ 58.8 and ≤ 60.5 Hz.

5. Not Used.

6. Simulating a loss of offsite power in conjunction with an ESF actuation test signal, and:

   a) Verifying de-energization of the vital bus and load shedding from the vital bus.

   b) Verifying the diesel starts on the auto-start signal*, energizes the vital bus with permanently connected loads within 13 seconds, energizes the auto-connected emergency (accident) loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization of these loads, the steady state voltage and frequency of the vital bus shall be maintained at ≥ 3910 and ≤ 4400 volts and ≥ 58.8 and ≤ 60.5 Hz during this test.

c) Verifying that all nonessential automatic diesel generator trips (i.e., other than engine overspeed, lube oil pressure low, 4 KV bus differential and generator differential), are automatically bypassed upon loss of voltage on the vital bus concurrent with a safety injection actuation signal.

7. Deleted

8. Verifying that the auto-connected loads to each diesel generator do not exceed the two hour rating of 2860 kw.

9. Verifying that with the diesel generator operating in a test mode (connected to its bus), a simulated safety injection signal overrides the test mode by (1) returning the diesel generator to standby operation and (2) automatically energizing the emergency loads with offsite power.

e. At least once per ten years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously*, during shutdown, and verifying that all diesel generators accelerate to at least 58.8 Hz in less than or equal to 13 seconds.

f. At least once per 18 months, the following test shall be performed within 5 minutes of diesel shutdown after the diesel has operated for at least two hours at 2340-2600 kw**:

Verifying the diesel generator starts and achieves $\geq$ 3910 volts and $\geq$ 58.8 Hz in $\leq$ 13 seconds, and subsequently achieves steady state voltage of $\geq$ 3910 and $\leq$ 4400 volts and frequency of 60 $\pm$ 1.2 Hz.

g. At least once per 18 months verifying the diesel generator operates for at least 24 hours*. During the first 2 hours of this test, the diesel generators shall be loaded to 2760-2860 Kw**. During the remaining 22 hours of this test, the diesel generator shall be loaded to 2500-2600 Kw**. The steady state voltage and frequency shall be maintained at $\geq$ 3910 and $\leq$ 4580 volts and 60 $\pm$ 1.2 Hz during this test.

4.8.1.1.3 The diesel fuel oil storage and transfer system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the level in each of the above required fuel storage tanks.

2. Verifying that both fuel transfer pumps can be started and transfer fuel from the fuel storage tanks to the day tanks.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days by verifying that a sample of diesel fuel from each of the above required fuel storage tanks is within the acceptable limits specified in Table 1 of ASTM D975-77 when checked for viscosity, water and sediment.

4.8.1.1.4 Reports - NOT USED

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* Surveillance testing may be conducted in accordance with the manufacturer's recommendations regarding engine prelube, warm-up and loading (unless loading times are specified in the individual Surveillance Requirements).

** This band is meant as guidance to preclude routine exceedances of the diesel generator manufacturer's design ratings. Loads in excess of this band for special testing or momentary variations due to changing bus loads shall not invalidate the test.

SURVEILLANCE REQUIREMENTS (Continued)

TABLE 4.8-1

DIESEL GENERATOR TEST SCHEDULE

NOT USED

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system (vital bus system), and

b. Two separate and independent diesel generators with:

   1. Separate day tanks containing a minimum volume of 130 gallons of fuel, and

   2. A common fuel storage system containing a minimum volume of 23,000 gallons of fuel, and

   3. A fuel transfer pump.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

a. With one of the above minimum required A.C. electrical power sources not OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, movement of irradiated fuel, and positive reactivity changes until the minimum required A.C. electrical power sources are restored to OPERABLE status.

b. With two of the required diesel generators not OPERABLE, suspend all operations involving CORE ALTERATIONS, movement of irradiated fuel, and all operations involving positive reactivity additions, and immediately initiate action to restore one required DG to OPERABLE status.

SURVEILLANCE REQUIREMENTS

---------------------------------------NOTE---------------------------------------
The following surveillances are not required to be performed to maintain operability during Modes 5 and 6. These surveillances are: 4.8.1.1.1.b, 4.8.1.1.2.d.2, 4.8.1.1.2.d.3, 4.8.1.1.2.d.4, 4.8.1.1.2.d.6, 4.8.1.1.2.d.9, 4.8.1.1.2.e, 4.8.1.1.2.f, and 4.8.1.1.2.g.

4.8.1.2 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Surveillance Requirements of 4.8.1.1.1, 4.8.1.1.2, 4.8.1.1.3 (except for requirement 4.8.1.1.3.a.2) and 4.8.1.1.4.

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A. C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generators:

4 kvolt	Vital Bus # 1A
4 kvolt	Vital Bus # 1B
4 kvolt	Vital Bus # 1C
460 volt	Vital Bus # 1A and associated control centers
460 volt	Vital Bus # 1B and associated control centers
460 volt	Vital Bus # 1C and associated control centers
230 volt	Vital Bus # 1A and associated control centers
230 volt	Vital Bus # 1B and associated control centers
230 volt	Vital Bus # 1C and associated control centers
115 volt	Vital Instrument Bus # 1A and Inverter *
115 volt	Vital Instrument Bus # 1B and Inverter *
115 volt	Vital Instrument Bus # 1C and Inverter *
115 volt	Vital Instrument Bus # 1D and inverter *

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With less than the above complement of A.C. busses OPERABLE or energized, restore the inoperable bus to OPERABLE and energized status within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one inverter inoperable, energize the associated A. C. Vital Bus within 8 hours; restore the inoperable 1A, 1B, or 1C inverter to OPERABLE and energized status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; restore the inoperable 1D inverter to OPERABLE and energized status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying correct breaker alignment and indicated power availability.

(*) An inverter may be disconnected from its DC source for up to 24 hours for the purpose of performing an equalizing charge on its associated battery bank provided (1) its vital bus is OPERABLE and energized, and (2) the vital busses associated with the other battery banks are OPERABLE and energized.

ELECTRICAL POWER SYSTEMS

A.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, two A.C. electrical bus trains shall be OPERABLE and energized from sources of power other than a diesel generator but aligned to an OPERABLE diesel generator with each train consisting of:

1 - 4 kvolt Vital Bus

1 - 460 volt Vital Bus and associated control centers

1 - 230 volt Vital Bus and associated control centers

1 - 115 volt Instrument Bus energized from its respective inverter connected to its respective D. C. bus train.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of A.C. busses and inverters OPERABLE and energized, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement of irradiated fuel assemblies until the minimum required A.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.2 The specified A.C. busses and inverters shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying correct breaker alignment and indicated voltage on the busses.

125-VOLT D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.3 The following D.C. bus trains shall be OPERABLE and energized:

TRAIN 1A	consisting of 125-volt D.C. bus No. 1A, 125-volt D.C. battery No. 1A and battery charger 1A1.
TRAIN 1B	consisting of 125-volt D.C. bus No. 1B, 125-volt D.C. battery No. 1B and battery charger 1B1.
TRAIN 1C	consisting of 125-volt D.C. bus No. 1C, 125-volt D.C. battery No. 1C and battery charger 1C1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one 125-volt D.C. bus inoperable or not energized, restore the inoperable bus to OPERABLE and energized status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one 125-volt D.C. battery charger inoperable, restore the inoperable charger to OPERABLE status within 2 hours or connect the backup charger for no more than 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one or more 125-volt D.C. batteries with one or more battery cell parameters not within the Category A or B limits of Table 4.8.2.3-1:

   1. Verify within 1 hour, that the electrolyte level and float voltage for the pilot cell meets Table 4.8.2.3-1 Category C limits, and

   2. Verify within 24 hours, that the battery cell parameters of all connected cells meet Table 4.8.2.3-1 Category C limits, and

   3. Restore battery cell parameters to Category A and B limits of Table 4.8.2.3-1 within 31 days, and

   4. If any of the above listed requirements cannot be met, comply with the requirements of action f.

d. With one or more 125-volt D.C. batteries with one or more battery cell parameters not within Table 4.8.2.3-1 Category C values, comply with the requirements of action f.

e. With average electrolyte temperature of representative cells less than 65°F, comply with the requirements of action f.

f. Restore the battery to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.3.1 Each D.C. bus train shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and power availability.

4.8.2.3.2 Each 125-volt battery and above required charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The parameters in Table 4.8.2.3-1 meet Category A limits.

2. The overall battery voltage is greater than or equal to 125 volts on float charge.

b. At least once per 92 days and once within 24 hours after a battery discharge < 110 V and once within 24 hours after a battery overcharge > 150 V by verifying that the parameters in Table 4.8.2.3-1 meet the Category B limits.

c. At least once per 92 days by verifying that:

1. There is no visible corrosion at terminals or connectors or the connection resistance is:

≤150 micro ohms for inter-cell connections,
≤350 micro ohms for inter-rack connections,
≤350 micro ohms for inter-tier connections,
≤70 micro ohms for field cable terminal connections, and
≤2500 micro ohms for the total battery connection

resistance which includes all inter-cell connections (including bus bars), all inter-rack connections (including cable resistance) all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

2. The average electrolyte temperature of the representative cells is above 65°F.

d. At least once per 12 months by verifying that:

1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration.

2. Remove visible terminal corrosion and verify cell-to-cell and terminal connections are coated with anti-corrosion material.

3. The connection resistance is:
   ≤ 150 micro ohms for inter-cell connections,
   ≤ 350 micro ohms for inter-rack connections,
   ≤ 350 micro ohms for inter-tier connections,
   ≤ 70 micro ohms for field cable terminal connections, and
   ≤ 2500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-rack connections (including cable resistance), all inter-tier connections (including cable resistance), and all field terminal connections at the battery.

e. At least once per 18 months by verifying that the battery charger will supply at least 170 amperes at 125 volts for at least 4 hours.

f.* At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

g. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Satisfactory completion of this performance discharge test shall also satisfy the requirements of Specification 4.8.2.3.2.f if the performance discharge test is conducted during a shutdown where that test and the battery service test would both be required.

h. At least once per 12 months, during shutdown, if the battery shows signs of degradation <u>OR</u> has reached 85% of the service life with a capacity less than 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

i. At least once per 24 months, during shutdown, if the battery has reached 85% of the service life with capacity greater than or equal to 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test.

* A one-time extension to this surveillance requirement is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

SURVEILLANCE REQUIREMENTS (Continued)

Table 4.8.2.3-1

Battery Cell Parameters Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE VALUE FOR EACH CONNECTED CELL
Electrolyte level	>Minimum level indication mark, and ≤1/4 above maximum level indication mark (a)	>Minimum level indication mark, and ≤1/4 above maximum level indication mark (a)	Above top of plates, and not overflowing
Float Voltage	≥2.13 volts	≥2.13 volts	≥2.07 volts
Specific Gravity (b) (c)	≥1.195	≥1.190 AND Average of all connected cells ≥1.200	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charge provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 3 amps when on float charge.

(c) Or battery charging current is < 3 amps when on float charge. This is acceptable only during a maximum of 7 days following a battery recharge.

125-VOLT D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.4 As a minimum, the following D.C. electrical equipment and bus shall be energized and OPERABLE:

2 - 125-volt D.C. busses, and

2 - 125-volt batteries, each with at least one full capacity charger, associated with each of the above D.C. busses.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of D.C. equipment and busses OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement of irradiated fuel assemblies until the minimum required 125Volt D.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.4.1 The above required 125-volt D.C. busses shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and indicated power availability.

4.8.2.4.2 The above required 125-volt batteries and chargers shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.3.2.

28-VOLT D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.5 The following D.C. bus trains shall be energized and OPERABLE:

TRAIN 1A consisting of 28-volt D.C. bus No. 1A, 28-volt D.C. battery No. 1A and battery charger 1A1.

TRAIN 1B consisting of 28-volt D.C. bus No. 1B, 28-volt D.C. battery No. 1B and battery charger 1B1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one 28-volt D.C. bus inoperable or not energized, restore the inoperable bus to OPERABLE and energized status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one required 28-volt D.C. battery charger inoperable, restore the inoperable battery charger to OPERABLE status within 2 hours or connect the backup charger for no more than 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one or more 28-volt D.C. batteries with one or more battery cell parameters not within the Category A or B limits of Table 4.8.2.5-1:

   1. Verify within 1 hour, that the electrolyte level and float voltage for the pilot cell meets Table 4.8.2.5-1 Category C limits, and
   2. Verify within 24 hours, that the battery cell parameters of all connected cells meet Table 4.8.2.5-1 Category C limits, and
   3. Restore battery cell parameters to Category A and B limits of Table 4.8.2.5-1 within 31 days, and
   4. If any of the above listed requirements cannot be met, comply with the requirements of action f.

d. With one or more 28-volt D.C. batteries with one or more battery cell parameters not within Table 4.8.2.5-1 Category C values, comply with the requirements of action f.

e. With average electrolyte temperature of representative cells less than 65°F, comply with the requirements of action f.

f. Restore the battery to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

4.8.2.5.1 Each D.C. bus train shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and power availability.

4.8.2.5.2 Each 28-volt battery and above required charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

    1. The parameters in Table 4.8.2.5-1 meet Category A limits.

    2. The overall battery voltage is greater than or equal to 27 volts on float charge.

b. At least once per 92 days and once within 24 hours after a battery discharge < 25.7 V and once within 24 hours after a battery overcharge > 35 V by verifying that the parameters in Table 4.8.2.5-1 meet the Category B limits,

c. At least once per 92 days by verifying that:

    1. There is no visible corrosion at terminals or connectors or the connection resistance is:

        ≤ 50 micro ohms for inter-cell connections,
        ≤ 200 micro ohms for inter-tier connections,
        ≤ 70 micro ohms for field cable terminal connections, and
        ≤ 500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

    2. The average electrolyte temperature of the representative cells is ≥ 65°F.

d. At least once per 12 months by verifying that:

    1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration.

    2. Remove visible terminal corrosion and verify cell-to-cell and terminal connections are coated with anti-corrosion material.

    3. The connection resistance is:

        ≤ 50 micro ohms for inter-cell connections,
        ≤ 200 micro ohms for inter-tier connections,
        ≤ 70 micro ohms for field cable terminal connections, and
        ≤ 500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

SURVEILLANCE REQUIREMENTS (Continued)

e. At least once per 18 months by verifying that the battery charger will supply ≥ 150 amperes at ≥ 28 volts for ≥ 4 hours.

f. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

g. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Satisfactory completion of this performance discharge test shall also satisfy the requirements of Specification 4.8.2.5.2.f if the performance discharge test is conducted during a shutdown where that test and the battery service test would both be required.

h. At least once per 12 months, during shutdown, if the battery shows signs of degradation OR has reached 85% of the service life with a capacity less than 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

i. At least once per 24 months, during shutdown, if the battery has reached 85% of the service life with capacity greater than or equal to 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test.

TABLE 4.8.2.5-1

BATTERY CELL PARAMETER REQUIREMENTS

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE VALUE FOR EACH CONNECTED CELL
Electrolyte Level	>Minimum level indication mark and ≤ 1/4 inch above maximum level indication mark[a]	>Minimum level indication mark and ≤ 1/4 inch above maximum level indication mark[a]	Above top of plates and not overflowing
Float Voltage	≥2.13 V	≥2.13 V	≥2.07 V
Specific Gravity[b] [c]	≥1.195	≥1.190 AND Average of all Connected cells ≥1.200	Not more than 0.020 below the average of all connected cells AND Average of all connected cells ≥1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charge provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 2 amps when on float charge.

(c) Or battery charging current is < 2 amps when on float charge. This is acceptable only during a maximum of 7 days following a battery recharge.

28-VOLT D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.6 As a minimum, the following D. C. electrical equipment and bus shall be energized and OPERABLE:

1 - 28-volt D.C. bus, and

1 - 28-volt battery and at least one full capacity charger associated with the above D.C. bus.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of D.C. equipment and busses OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement or irradiated fuel assemblies until the minimum required 28Volt D.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.6.1 The above required 28-volt D.C. bus shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and voltage on the bus.

4.8.2.6.2 The above required 28-volt batteries and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.5.2.

3/4 8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.3.1 All containment penetration conductor overcurrent protective devices required to provide thermal protection of penetrations shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the required containment penetration conductor overcurrent protective device(s) inoperable:

a. Restore the protective device(s) to OPERABLE status or de-energize the circuit(s) by tripping either the primary or backup protective device, or racking out or removing the primary or backup device within 72 hours, declare the affected system or component inoperable, and verify the primary or backup protective device to be tripped, or the primary or backup device racked out or removed at least once per 7 days thereafter; or

b. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.3.1 All required containment penetration conductor overcurrent protective devices shall be demonstrated OPERABLE:

a. At least once per 18 months:

1.*,** For at least one 4.16 KV reactor coolant pump circuit, such that all reactor coolant pump circuits are demonstrated OPERABLE at least once per 72 months, by performance of:

(a) A CHANNEL CALIBRATION of the associated protective relays, and

(b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed.

* A one time extension to this surveillance requirement for inspection calibration and meggaring of the 1F 4KV Bus overload relays, which partially satisfies this surveillance requirement, is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

** A one time extension to this surveillance requirement for inspection calibration and meggaring of the 1A, 1B, and 1C 460 transformer relays and CT's, which partially satisfy this surveillance requirement, is granted during fuel cycle thirteen allowing Unit 1 operations to continue to the thirteenth refueling outage (1R13). The surveillance testing is to be completed at the appropriate time during the 1R13 outage, prior to the unit returning to Mode 4 upon outage completion.

SURVEILLANCE REQUIREMENTS (Continued)

2. By verifying the OPERABILITY of the required molded case and lower voltage circuit breakers, by selecting and functionally testing a representative sample of at least 10% of all the circuit breakers of that type. Circuit breakers selected for functional testing shall be selected on a rotating basis. The functional test shall consist of injecting a current input at the specified setpoint to each selected circuit breaker and verifying that each circuit breaker functions as designed. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during the functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

3/4.9 REFUELING OPERATIONS

BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of the Reactor Coolant System, the fuel storage pool, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODE 6 (Only applicable to the refueling canal, the fuel storage pool and refueling cavity when connected to the Reactor Coolant System)

ACTION:

With the requirements of the above specification not satisfied, immediately

a. Suspend CORE ALTERATIONS and

b. Suspend positive reactivity additions and

c. Initiate action to restore boron concentration to within limit specified in the COLR.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.1. Verify the boron concentration is within the limit of the COLR every 72 hours.

REFUELING OPERATIONS

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 As a minimum, two source range neutron flux monitors shall be operating, each with continuous visual indication in the control room and one with audible indication in the containment and control room.

APPLICABILITY: MODE 6.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.2 Each source range neutron flux monitor shall be demonstrated OPERABLE by performance of:

a. A CHANNEL FUNCTIONAL TEST at least once per 7 days, and

b. A CHANNEL CHECK at least once per 12 hours during CORE ALTERATIONS.

DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.3 The reactor shall be subcritical for at least:.

a. 100 hours - Applicable through year 2010.
b. 168 hours

APPLICABILITY: Specification 3.9.3.a - From October 15th through May 15th, during movement of irradiated fuel in the reactor pressure vessel.

Specification 3.9.3.b - From May 16th through October 14th, during movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than the required time, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.3 The reactor shall be determined to have been subcritical as required by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

CONTAINMENT BUILDING PENETRATIONS

LIMITING CONDITION FOR OPERATION

3.9.4 The containment building penetrations shall be in the following status:

a. The equipment hatch inside door is capable of being closed and held in place by a minimum of four bolts, or an equivalent closure device installed and capable of being closed,

b. A minimum of one door in each airlock is capable of being closed

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either:

1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or
2. capable of being closed by the Containment Purge and Pressure-Vacuum Relief Isolation System.

Note: Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During movement of irradiated fuel within the containment.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving movement of irradiated fuel in the containment building. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.4.1 Each of the above required containment building penetrations shall be determined to be either in its required condition or capable of being closed by a manual or automatic containment isolation valve at least once per 7 days.

4.9.4.2 Once per refueling prior to the start of movement of irradiated fuel assemblies within the containment building, verify the capability to install, within 1 hour, the equipment hatch. Applicable only when the equipment hatch is open during movement of irradiated fuel in the containment building.

4.9.4.3 Verify, once per 18 months, each required containment purge isolation valve actuates to the isolation position on a manual actuation signal.

COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communications shall be maintained between the control room and personnel at the refueling station.

APPLICABILITY: During CORE ALTERATIONS.

ACTION:

When direct communications between the control room and personnel at the refueling station cannot be maintained, suspend all CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communications between the control room and personnel at the refueling station shall be demonstrated within one hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.

MANIPULATOR CRANE OPERABILITY

LIMITING CONDITION FOR OPERATION

3.9.6 The manipulator crane and auxiliary hoist shall be used for movement of control rods or fuel assemblies and shall be OPERABLE with:

a. The manipulator crane used for movement of fuel assemblies having:

1. A minimum capacity of 3250 pounds, and

2. An overload cut off limit less than or equal to 2850 pounds.

b. The auxiliary hoist used for movement of control rods having:

1. A minimum capacity of 700 pounds, and

2. A load indicator which shall be used to prevent lifting loads in excess of 600 pounds.

APPLICABILITY: During movement of control rods or fuel assemblies within the reactor pressure vessel.

ACTION:

With the requirements for crane and/or hoist OPERABILITY not satisfied, suspend use of any inoperable manipulator crane and/or auxiliary hoist from operations involving the movement of control rods and fuel assemblies within the reactor pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.6.1 Each manipulator crane used for movement of fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 3250 pounds and demonstrating an automatic load cut off set at less than or equal to 2850 pounds; this includes the heavy load plus the weight of the crane mast and gripper.

4.9.6.2 Each auxiliary hoist and associated load indicator used for movement of control rods within the reactor pressure vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 700 pounds.

CRANE TRAVEL - FUEL HANDLING AREA

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 2200 pounds shall be prohibited from travel over fuel assemblies in the storage pool.

APPLICABILITY: With fuel assemblies in the storage pool.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 The overload cutoff which prevents crane travel with loads in excess of 2200 pounds over fuel assemblies shall be demonstrated OPERABLE within 7 days prior to crane use and at least once per 7 days thereafter during the crane operation.

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION ALL WATER LEVELS

LIMITING CONDITION FOR OPERATION

3.9.8.1 At least one residual heat removal loop shall be in operation.

APPLICABILITY: MODE 6.

ACTION:

a. With less than one residual heat removal loop in operation, except as provided in b. below, suspend all operations involving an increase in the reactor decay heat load or a reduction in boron concentration of the Reactor Coolant System. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

b. The residual heat removal loop may be removed from operation for up to 1 hour per 8 hour period during the performance of CORE ALTERATIONS in the vicinity of the reactor pressure vessel hot legs.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.1 At least once per 12 hours one RHR loop shall be verified in operation and circulating coolant at a flow rate of:

a. greater than or equal to 1000 gpm, and
b. sufficient to maintain the RCS temperature at less than or equal to 140°F.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent Residual Heat Removal (RHR) loops shall be OPERABLE.*

APPLICABILITY: MODE 6 when water level above the top of the reactor pressure vessel flange is less than 23 feet.

ACTION:

a. With less than the required RHR loops operable, immediately initiate corrective action to return the required RHR loops to OPERABLE status as soon as possible.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.2 The required Residual Heat Removal loops shall be determined OPERABLE per Specification 4.0.5.

* Systems supporting RHR loop operability may be excepted as follows:

a. The normal or emergency power source may be inoperable.

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REFUELING OPERATIONS

WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.10 At least 23 feet of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During movement of fuel assemblies or control rods within the reactor pressure vessel while in MODE 6.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving movement of fuel assemblies or control rods within the pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.10 The water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and at least once per 24 hours thereafter during movements of fuel assemblies or control rods.

REFUELING OPERATIONS

STORAGE POOL WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11 At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the storage pool.

ACTION:

With the requirements of the specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the fuel storage areas and restore water level to within its limit within 4 hours. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.11 The water level in the storage pool shall be determined to be at least its minimum required depth at least once per 7 days when irradiated fuel assemblies are in the fuel storage pool.

FUEL HANDLING AREA VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 The Fuel Handling Area Ventilation System shall be OPERABLE with:

a. Two exhaust fans and one supply fan OPERABLE and operating, and
b. Capable of maintaining slightly negative pressure in the Fuel Handling Building.

APPLICABILITY: During movement of irradiated fuel within the Fuel Handling Building

ACTION:

a. With no Fuel Handling Area Ventilation System OPERABLE, suspend all operations involving movement of fuel within the storage pool until the Fuel Handling Area Ventilation System is restored to OPERABLE status.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.12 The above required ventilation system shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that, the Fuel Handling Building is maintained at a slightly negative pressure with respect to atmospheric pressure.

b. At least once per 31 days by verifying both exhaust fans and one supply fan start and operate for at least 15 minutes, if not operating already.

c. At least once per 18 months by verifying a system flowrate of 19,490 cfm ± 10% during system operation.

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3/4.10 SPECIAL TEST EXCEPTIONS

SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.10.1 The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 may be suspended for measurement of control rod worth and shutdown margin provided the reactivity equivalent to at least the highest estimated control rod worth is available for trip insertion from OPERABLE control rod(s).

APPLICABILITY: MODE 2.

ACTION:

a. With any full length control rod not fully inserted and with less than the above reactivity equivalent available for trip insertion, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

b. With all full length control rods inserted and the reactor subcritical by less than the above reactivity equivalent, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

SURVEILLANCE REQUIREMENTS

4.10.1.1 The position of each full length and part length rod either partially or FULLY WITHDRAWN shall be determined at least once per 2 hours.

4.10.1.2 Each full length rod not fully inserted shall be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position within 24 hours prior to reducing the SHUTDOWN MARGIN to less than the limits of Specification 3.1.1.1.

SPECIAL TEST EXCEPTIONS

GROUP HEIGHT, INSERTION AND POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The group height, insertion and power distribution limits of Specifications 3.1.3.1, 3.1.3.4, 3.1.3.5, 3.2.1, and 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER is maintained ≤ 85% of RATED THERMAL POWER, and

b. The limits of Specifications 3.2.2 and 3.2.3 are maintained and determined at the frequencies specified in Specification 4.10.2.2 below.

APPLICABILITY: MODE 1

ACTION:

With any of the limits of Specifications 3.2.2 or 3.2.3 being exceeded while the requirements of Specifications 3.1.3.1, 3.1.3.4, 3.1.3.5, 3.2.1 and 3.2.4 are suspended, either:

a. Reduce THERMAL POWER sufficient to satisfy the ACTION requirements of Specifications 3.2.2 and 3.2.3, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined to be ≤ 85% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

4.10.2.2 The below listed surveillance requirements shall be performed at least once per 12 hours during PHYSICS TESTS:

a. Surveillances 4.2.2.2 and 4.2.2.3.

b. Surveillances 4.2.3.1 and 4.2.3.2.

SPECIAL TEST EXCEPTIONS

PHYSICS TESTS

LIMITING CONDITION FOR OPERATION

3.10.3 The limitations of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.4, and 3.1.3.5 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER, and

b. The reactor trip setpoints on the OPERABLE Intermediate and Power Range Nuclear Channels are set at ≤ 25% of RATED THERMAL POWER.

APPLICABILITY: MODE 2.

ACTION:

With the THERMAL POWER > 5% of RATED THERMAL POWER, immediately open the reactor trip breakers.

SURVEILLANCE REQUIREMENTS

4.10.3.1 The THERMAL POWER shall be determined to be ≤ 5% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

4.10.3.2 Each Intermediate and Power Range Channel shall be subjected to a CHANNEL FUNCTIONAL TEST prior to initiating PHYSICS TESTS.

SPECIAL TEST EXCEPTION

NO FLOW TESTS

LIMITING CONDITION FOR OPERATION

3.10.4 The limitations of Specification 3.4.1.1 may be suspended during the performance of startup and PHYSICS TESTS, provided:

a. The THERMAL POWER does not exceed the P-7 Interlock Setpoint, and

b. The Reactor Trip Setpoints on the OPERABLE Intermediate and Power Range Channels are set ≤ 25% of RATED THERMAL POWER

APPLICABILITY: During operation below the P-7 Interlock Setpoint.

ACTION:

With the THERMAL POWER greater than the P-7 Interlock Setpoint, immediately open the reactor trip breakers.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The THERMAL POWER shall be determined to be less than P-7 Interlock Setpoint at least once per hour during startup and PHYSICS TESTS.

4.10.4.2 Each Intermediate, Power Range Channel and P-7 Interlock shall be subjected to a CHANNEL FUNCTIONAL TEST prior to initiating startup or PHYSICS TESTS.

3/4.11 RADIOACTIVE EFFLUENTS

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RADIOACTIVE EFFLUENTS

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RADIOACTIVE EFFLUENTS

LIQUID HOLDUP TANKS*

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in each outdoor temporary tank shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each outdoor temporary tank shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

* Tanks included in this Specification are those outdoor temporary tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

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RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of oxygen in the waste gas holdup system shall be limited to less than or equal to 2% by volume.

APPLICABILITY: At all times. *

ACTION:

a. With the concentration of oxygen in the waste gas holdup system greater than 2% by volume but less than or equal to 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

b. With the concentration of oxygen in the waste gas holdup system greater than 4% by volume immediately suspend all additions of waste gases to the system and reduce the concentration of oxygen to less than or equal to 2% by volume without delay.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5 The concentration of oxygen in the waste gas holdup system shall be determined to be within the above limits by continuously** monitoring the waste gases in the waste gas holdup system with the oxygen monitor. If hydrogen is not measured, the concentration of hydrogen shall be assumed to exceed 4% by volume.

* Not applicable to portions of the Waste Gas System removed from service for maintenance provided that, the portions removed for maintenance are isolated, and purged of hydrogen to less than 4% by volume.

** If the oxygen monitoring instrumentation is inoperable, operation of the waste gas holdup system may continue provided grab samples are collected at least once per 24 hours and analyzed within the following 4 hours.

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BASES

Specification 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL MODES or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in a MODE or condition in which the specification no longer applies. It is not intended that the shutdown ACTION requirements be used as an operational convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

The specified time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered a MODE in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exist. when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown MODE when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or the time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in the COLD SHUTDOWN MODE when a shutdown is required during the POWER MODE of operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE of operation applies. However, if a lower MODE of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other applicable MODE, is not reduced. For example, if HOT STANDBY is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because of the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do not apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management

personnel, actions to reduce the duration of the condition, actions to minimize the
magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these system and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on an ACTION in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications that describe values and parameters (e.g., Containment Air Temperature, Containment Pressure, Moderator Temperature Coefficient), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and

Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 4.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 4.0.1 or SR 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

Specification 3.0.5

DELETED

Specification 3.0.6 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of testing required to restore and demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the testing required to restore and demonstrate the operability of the equipment. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the testing required to restore and demonstrate OPERABILITY.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of testing required to restore OPERABILITY of another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of testing required to restore and demonstrate the OPERABILITY of another channel in the same trip system.

APPLICABILITY

BASES

Specifications 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that Surveillance Requirements must be met during the OPERATIONAL MODES or other specified conditions in the Applicability for which the requirements of the Limiting Conditions for Operation apply, unless otherwise specified in an individual Surveillance Requirement. This specification is to ensure that surveillances are performed to verify the OPERABILITY of systems and components and that variables are within specified limits.

Failure to meet a Surveillance within the specified Frequency, in accordance with Specification 4.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated Surveillance Requirements have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when either:

a. The systems or components are known to be inoperable, although still meeting the Surveillance Requirements, or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the facility is in an OPERATIONAL MODE or other specified condition for which the requirements of the associated Limiting Condition for Operation do not apply, unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given Surveillance. In this case, the unplanned event may be credited as fulfilling the performance of the Surveillance Requirement. This allowance includes those Surveillances whose performance is normally precluded in a given OPERATIONAL MODE or other specified condition.

Surveillances, including Surveillances invoked by ACTIONS, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2 prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Auxiliary Feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures > 680 psig. However, if other appropriate testing is satisfactorily completed, the AFW system can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

b. High Pressure Safety Injection (HPI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

<u>Specification 4.0.2</u> establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that ... not be suitable for conducting the surveillance; e.g., transient ...ions or other ongoing surveillance or maintenance activities. It also ...es flexibility to accommodate the length of a fuel cycle for ...eillances that are performed at each refueling outage and are specified with an 18 month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

<u>Specification 4.0.3</u> establishes the flexibility to defer declaring affected equipment inoperable, or an affected variable outside the specified limits, when a Surveillance has not been completed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with TS 3.0.2, and not at the time that the specified frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 4.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity. SR 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified frequencies for Surveillances is expected to be an infrequent occurrence. Use of the delay period established by SR 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance.

This risk impact should be managed through the program in place to implement 10 CFR50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable, or the variable is considered outside the specified limits, and the Completion Times of the Required Actions for the applicable LCO begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits, and the Completions Times of the Required Actions for the applicable LCO begins immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the Actions, restores compliance with SR 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

However, in two certain circumstances, failing to meet an SR will not result in SR 4.0.4 restricting a MODE change or other specified condition change:

(1) When a system, subsystem, division, component, device or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 4.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

(2) SR 4.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 4.0.3.

The provisions of SR 4.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 4.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 4.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a. These requirements apply except when relief has been provided in writing by the Commission.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL MODE or

other specified condition takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, that is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.3% $\Delta k/k$ is initially required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR safety analysis assumptions. With $T_{avg} \leq 200°F$, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% $\Delta k/k$ shutdown margin provides adequate protection.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting condition assumed in the accident and transient analyses.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC) (Continued)

The MTC values of this specification are applicable to a specific set of plant conditions; accordingly, verification of MTC values at conditions other than those explicitly stated will require extrapolation to those conditions in order to permit an accurate comparison.

The most negative MTC value equivalent to the most positive moderator density coefficient (MDC), was obtained by incrementally correcting the MDC used in the FSAR analysis to nominal operating conditions. These corrections involved: (1) a conversion of the MDC used in the FSAR analysis to its equivalent MTC, based on the rate of change of moderator density with temperature at RATED THERMAL POWER conditions, and (2) subtracting from this value the largest differences in MTC observed between EOL, all rods withdrawn, RATED THERMAL POWER conditions, and those most adverse conditions of moderator temperature and pressure, rod insertion, axial power skewing, and xenon concentration that can occur in normal operation and lead to a significantly more negative EOL MTC at RATED THERMAL POWER. These corrections transformed the MDC value used in the FSAR analysis into the limiting End of Cycle Life (EOL) MTC value. The 300 ppm surveillance limit MTC value represents a conservative value at a core condition of 300 ppm equilibrium boron concentration that is obtained by correcting the limiting EOL MTC for burnup and boron concentration.

The surveillance requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains with its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.1.1.5 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 541°F. This limitation is required to ensure 1) the moderator temperature coefficient is within its analyzed temperature range, 2) the protective instrumentation is within its normal operating range, 3) the P-12 interlock is above its allowable setpoint, 4) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and 5) the reactor pressure vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The boron injection system ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include: 1) borated water sources, 2) charging pumps, 3) separate flow paths, 4) boric acid transfer pumps, and 5) offsite power or an emergency power supply from OPERABLE diesel generators.

With the RCS average temperature ≥ 350°F, a minimum of two boron injection flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable. The boration capability of either flow path is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of 1.3% delta k/k after xenon decay and cooldown to 200°F. The maximum expected boration capability (minimum boration volume) requirement is established to conservatively bound expected operating conditions throughout core operating life. The analysis assumes that the most reactive control rod is not inserted into the core. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires borated water from a boric acid tank in accordance with TS Figure 3.1-2, and additional makeup from either: (1) the second boric acid tank and/or batching, or (2) a maximum of 41,800 gallons of 2,300 ppm borated water from the refueling water storage tank. With the refueling water storage tank as the only borated water source, a maximum of 73,800 gallons of 2,300 ppm borated water is required. However, to be consistent with the ECCS requirements, the RWST is required to have a minimum contained volume of 364,500 gallons during operations in MODES 1, 2, 3 and 4.

The boric acid tanks, pumps, valves, and piping contain a boric acid solution concentration of between 3.75% and 4.0% by weight. To ensure that the boric acid remains in solution, the tank fluid temperature and the process pipe wall temperatures are monitored to ensure a temperature of 63°F, or above is maintained. The tank fluid and pipe wall temperatures are monitored in the main control room. A 5°F margin is provided to ensure the boron will not precipitate out.

Should ambient temperature decrease below 63°F, the boric acid tank heaters, in conjunction with boric acid pump recirculation, are capable of maintaining the boric acid in the tank and in the pump at or above 63°F. A small amount of boric acid in the flow path between the boric acid recirculation line and the suction line to the charging pump will precipitate out, but it will not cause flow blockage even with temperatures below 50°F.

With the RCS temperature below 350°F, one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity change in the event the single injection system becomes inoperable.

The boron capability required below 200 °F in sufficient to provide a SHUTDOWN MARGIN of 1% delta k/k after xenon decay and cooldown from 200 °F to 140 °F. This condition requires either 2,600 gallons of 6,560 ppm borated water from the boric acid storage tanks or 7,100 gallons of 2,300 ppm borated water from the refueling water storage tank.

The 37,000 gallons limit in the refueling water storage tank for Modes 5 and 6 is based upon 21,210 gallons that is undetectable due to lower tap location, 8,550 gallons for instrument error, 7,100 gallons required for shutdown margin, and an additional 140 gallons due to rounding up.

The limits on contained water volume and boron concentration of the RWST also ensure a pH value of between 7.0 and 10.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The contained water volume limits include allowance for water not available because of discharge line location and other physical characteristics. The OPERABILITY of one boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) limit the potential effects of rod mis-alignment on associated accident analyses. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure ompliance with the control rod alignment and insertion limits. OPERABLE condition for the analog rod position indicators is defined as being capable of indicating rod position to within the allowed rod misalignment relative to the bank demand position for a range of positions. For the Shutdown Banks and Control Bank A this range is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 and 228 steps withdrawn inclusive. This permits the operator to verify that the control rods in these Banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these banks positions in these ranges satisfies all accident analysis assumptions concerning their position. The range for control Bank B is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 160 and 228 steps withdrawn inclusive. For Control Banks C and D the range is, defined as the group demand counter indicated position between 0 and 228 steps, withdrawn. Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the insertion limits. The full out position will be specifically established for each cycle by the Reload Safety Analysis for that cycle. This position will be within the band established by "FULL WITHDRAWN" and will be administratively controlled. This band is allowable to minimize RCCA wear, pursuant to Information Notice 87-19

The ACTION statements which permit limited variation from the basic requirements are accompanied by additional restrictions which ensure that the original criteria are met. Mis-alignment of a rod requires measurement of peaking factors or a restriction in THERMAL POWER; either of these restrictions provide assurance of fuel rod integrity during continued operation. The reactivity worth of a mis-aligned rod is limited for the remainder of the fuel cycle to prevent exceeding the assumption used in the accident analysis.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the accident analyses. Measurement with T_{avg} >541°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

Control rod positions and OPERABILITY of the rod position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCO's are satisfied.

The terms "Shutdown Rod Position Indicator", "Analog Rod Position Indicator", "Control Rod Position Indicator", and Rod Position Indicator" are all used in this bases section or in the Technical Specifications, and all refer to indication driven by the output of the Analog Rod Position Indication (ARPI) system.

One method for determining rod position are the indicators on the control console. An alternate method of determining rod position is the plant computer. Either the control console indicator or plant computer is sufficient to comply with this specification. The plant computer receives the same input from ARPI as the control console indicators and provides resolution equivalent to or better than the control console indicators. The plant computer also provides a digital readout of rod position which eliminates interpolation and parallax errors inherent to analog scales.

Rod demand position is indicated on the control console and the plant computer. The rod demand position is a digital signal, namely a pulse, and is generated each time the Rod Control System demands a rod position step change, one pulse for each rod step. The pulses are "counted" and displayed by the control console group demand step counters. There are two group demand step counters for each bank of rods with exception of shutdown banks C and D. The plant computer also "counts" and displays the demand pulses. Only the group 1 demand position of each rod bank is displayed on the plant computer as only the group 1 pulses are routed to the plant computer. The group 1 demand position on the plant computer is, by default, called "Cont Bank A Steps" or "S/D Bank A Steps" etc. with no reference to group 1 or group 2.

As the plant computer receives the same demand pulses from the Rod Control System as the control console group demand step counters and provides equivalent resolution, the plant computer "bank step" display provides an alternate method of determining group 1 rod demand position. Either the control console group 1 demand step counter or the plant computer "bank step" display is sufficient to comply with this specification for group 1 rod demand position. Only the control console group 2 demand counter can be used to comply with the specification for group 2 rod demand.

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (a) meeting the DNB design criterion during normal operation and in short term transients, and (b) limiting the fission gas release, fuel pellet temperature and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is not exceeded.

The definitions of hot channel factors as used in these specifications are as follows:

$F_Q(Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

$F_{xy}(Z)$ Radial Peaking Factor is defined as the ratio of peak power density to average power density in the horizontal plane at core elevation Z.

3/4.2.1 AXIAL FLUX DIFFERENCE (AFD)

The limits on AXIAL FLUX DIFFERENCE assure that the $F_Q(Z)$ upper bound envelope of the F_Q limit specified in the Core Operating Limits Report (COLR) times the normalized axial peaking factor is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

Target flux difference is determined at equilibrium xenon conditions. The full length rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

Although it is intended that the plant will be operated with the AXIAL FLUX DIFFERENCE within the target band in the COLR per Specification 3.2.1 about the target flux difference, during rapid plant THERMAL POWER reductions, control rod motion will cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation will not affect the xenon redistribution sufficiently to change the envelope of peaking factors which may be reached on a subsequent return to RATED THERMAL POWER (with the AFD within the target band) provided the time duration of the deviation is limited. Accordingly, a 1 hour penalty deviation limit cumulative during the previous 24 hours is provided for operation outside of the target band but within the limits specified in the COLR while at THERMAL POWER levels between 50% and 90% of RATED THERMAL POWER. For THERMAL POWER levels between 15% and 50% of rated THERMAL POWER, deviations of the AFD outside of the target band are less significant. The penalty of 2 hours actual time reflects this reduced significance.

Provisions for monitoring the AFD are derived from the plant nuclear instrumentation system through the AFD Monitor Alarm. A control room recorder continuously displays the auctioneered high flux difference and the target band limits as a function of power level. An alarm is received any time the auctioneered high flux difference exceeds the target band limits. Time outside the target band is graphically presented on the strip chart.

Figure B 3/4 2-1 shows a typical monthly target band.

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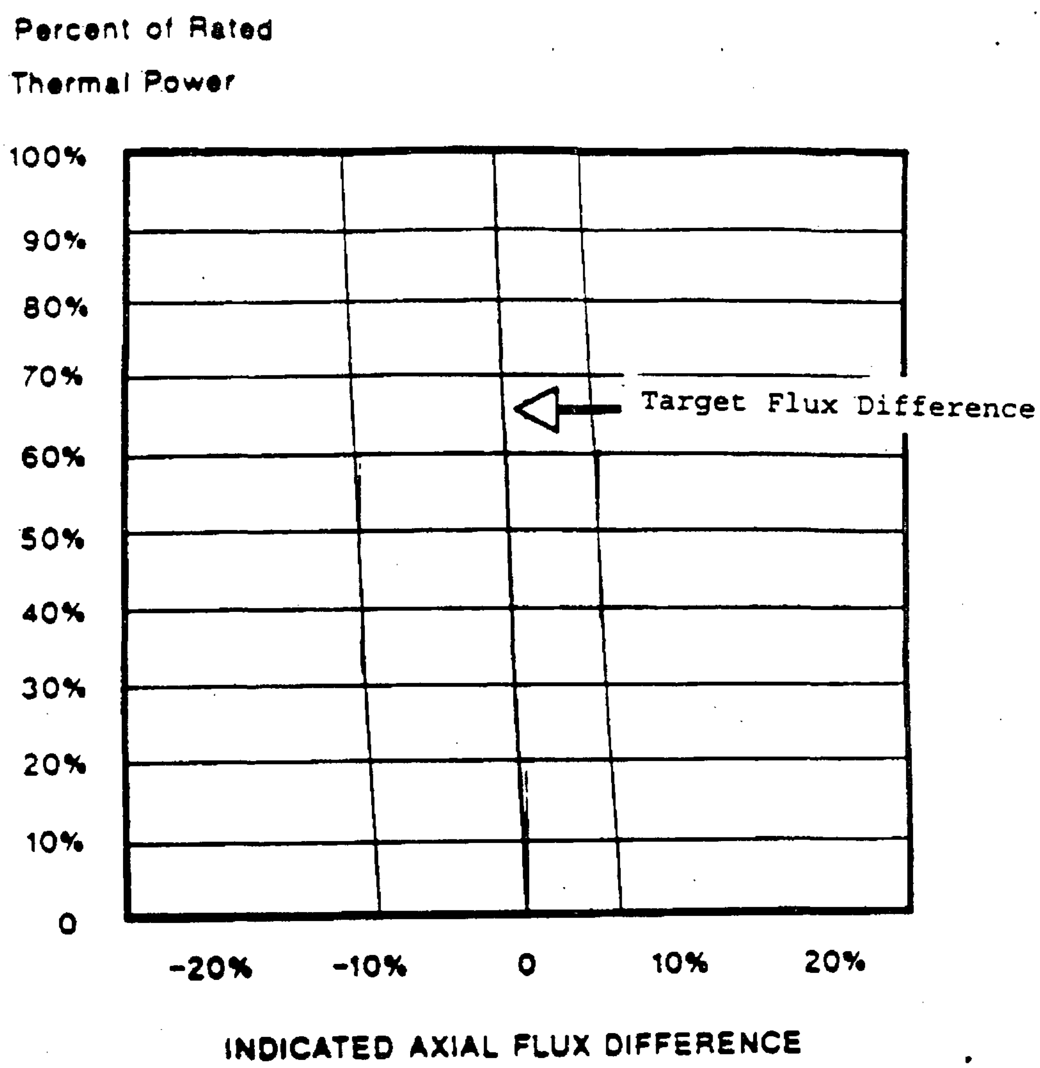

Figure B 3/4 2-1 TYPICAL INDICATED AXIAL FLUX DIFFERENCE VERSUS THERMAL POWER

* Refer to COLR Figure 2 for Actual Limits

3/4.2.2 and 3/4.2.3 HEAT FLUX AND NUCLEAR ENTHALPY HOT CHANNEL AND RADIAL PEAKING FACTORS - $F_Q(Z)$, F^N_{DH} and $F_{xy}(Z)$

The limits on heat flux and nuclear enthalpy hot channel factors ensure that 1) the design limits on peak local power density and minimum DNBR are not exceeded and 2) in the event of a LOCA the peak fuel clad temperature will not exceed the 2200°F ECCS acceptance criteria limit.

Each of these hot channel factors are measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to insure that the hot channel factor limits are maintained provided:

a. Control rod in a single group move together with no individual rod insertion differing from the group demand position by more than the allowed rod mislagnment.

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.5.

c. The control rod insertion limits of Specifications 3.1.3.4 and 3.1.3.5 are maintained.

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

The relaxation in F^N_{DH} as a function of THERMAL POWER allows changes in the radial power shape for all permissible rod insertion limits. F^N_{DH} will be maintained within its limits provided conditions a thru d above, are maintained.

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for 5% is the appropriate allowance for a full core map taken with the incore detector flux mapping system and 3% is the appropriate allowance for manufacturing tolerance. For measurements obtained using the Power Distribution Monitoring System (PDMS), the appropriate measurement uncertainty is determined using the measurement uncertainty methodology contained in WCAP 12472-P-A. The cycle and plant uncertainty calculation information needed to support the PDMS calculation is contained in the COLR. The PDMS will automatically calculate and apply the correct measurement uncertainty, and apply a 3% allowance for manufacturing tolerance.

When F^N_{DH} is measured, experimental error must be allowed for and is obtained from the COLR when using the PDMS or the incore detection system. The specified limit for F^N_{DH} also contains an 8% allowance for uncertainties which mean that normal operation will result in $F^N_{DH} \leq F^{RTP}_{DH} /1.08$ where F^{RTP}_{DH} is the limit of RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT (COLR). The 8% allowance is based on the following considerations:

a. abnormal perturbations in the radial power shape, such as from rod misalignment, effect $F^N_{\Delta H}$ more directly F_Q,

b. although rod movement has a direct influence upon limiting F_Q to within its limit, such control is not readily available to limit $F^N_{\Delta H}$, and

c. errors in prediction for control power shape detected during startup physics tests can be compensated for in F_Q by restricting axial flux distributions. This compensation for $F^N_{\Delta H}$ is less readily available.

The appropriate measurement uncertainty for $F^N_{\Delta H}$ obtained using PDMS is determined using the measurement uncertainty methodology contained in WCAP 12472-P-A. The cycle and plant specific uncertainty information needed to support the PDMS calculation is contained in the COLR. The PDMS will automatically calculate and apply the correct measurement uncertainty to the measured $F^N_{\Delta H}$.

The radial peaking factor $F_{xy}(z)$ is measured periodically to provide assurance that the hot channel factor, $F_Q(z)$, remains within its limit. The F_{xy} limit for Rated Thermal Power (F^{RTP}_{xy}), as provided in the COLR per specification 6.9.1.9, was determined from expected power control maneuvers over the full range of burnup conditions in the core.

3/4.2.4 QUADRANT POWER TILT RATIO

The quadrant power tilt ratio limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during startup testing and periodically during power operation.

The limit of 1.02 at which corrective action is required provides DNB and linear heat generation rate protection with x-y plane power tilts. A limiting tilt of 1.025 can be tolerated before the margin for uncertainty in F_Q is depleted. The limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The two hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the power by 3 percent from RATED THERMAL POWER for each percent of tilt in excess of 1.0.

3/4.2.5 DNB PARAMETERS

The limits on the DNB related parameters assure that each of the parameters are maintained within the normal steady state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR of the design DNBR value throughout each analyzed transient.

The 12 hour periodic surveillance of these parameters thru instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 18 month periodic measurement of the RCS total flow rate is adequate to detect flow degradation and ensure correlation of the flow indication channels with measured flow such that the indicated percent flow will provide sufficient verification of flow rate on a 12 hour basis.

3/4.3.1 and 3/4.3.2 PROTECTIVE AND ENGINEERED SAFETY FEATURES (ESF) INSTRUMENTATION

The OPERABILITY of the protective and ESF instrumentation systems and interlocks ensure that 1) the associated ESF action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation and, 3) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundance and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses.

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as-left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy).

The Trip Setpoints used in the bistables are based on the analytical limits stated in the UFSAR. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those Reactor Protection System (RPS) channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints and Allowable Values specified in the Technical Specification Limiting Conditions for Operation (LCO's) are conservatively adjusted with respect to the analytical limits. The methodology used to calculate the Trip Setpoints is consistent with Instrument Society of America standard ISA-S67.04-1982, which is endorsed via NRC Regulatory Guide 1.105, Rev. 2. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the safety analyses which demonstrate that safety limits are not violated remain valid (provided the unit is operated within the LCO's at the onset of any design basis event and the equipment functions as designed).

The Trip Setpoints and Allowable Values listed in the LCO's incorporate all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection

Instrumentation System," and Supplements to that report. Surveillance intervals and out of service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.

The verification of response time at the specified frequencies provides assurance that the reactor trip and the engineered safety features actuation associated with each channel is completed within the time limit assumed in the safety analysis. Response Time acceptance criteria have been relocated to UFSAR Sections 7.2 and 7.3 tables. No credit is taken in the analysis for those channels with response times indicated as not applicable (i.e., N.A.).

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types, and other components that do not have plant-specific NRC approval to use alternate means of verification, must be demonstrated by test.

The allocation for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

Channel testing in a bypassed condition shall be performed without lifting leads or jumpering bistables.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring channels ensures that 1) the radiation levels are continually measured in the areas served by the individual channels and 2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded.

In the postulated Fuel Handling Accident, the revised dose calculations, performed using 10 CFR 50.67 and Regulatory Guide 1.183, Alternative Source Term, do not take credit for automatic containment purge isolation thus allowing for continuous monitoring of containment activity until containment closure is achieved. If required, containment purge isolation can be initiated manually from the control room.

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION (Continued)

CROSS REFERENCE - TABLES 3.3-6 AND 4.3-3

T/S Table Item No.	Instrument Description	Acceptable RMs Channels
1a	Fuel Storage Area	1R5 or 1R9
1b	DELETED	
2a1a	Containment Gaseous Activity Purge & Pressure/Vacuum Relief Isolation	1R12A or 1R41A, and D(1) (2)
2a1b	Containment Gaseous Activity RCS Leakage Detection	1R12A
2a2a	(NOT USED)	
2a2b	Containment Air Particulate Activity RCS Leakage Detection	1R11A
2b1	Noble Gas Effluent Medium Range Auxiliary Building Exhaust System (Plant Vent)	1R41B & D (1) (3) (5)
2b2	Noble Gas Effluent High Range Auxiliary Building Exhaust System (Plant Vent)	1R41C & D (1) (4) (5)
2b3	DELETED	
2b4	Noble Gas Effluent Condenser Exhaust System	1R15
3a	Unit 1 Control Room Intake Channel 1 (to Unit 1 Monitor)	1R1B-1
	Unit 1 Control Room Intake Channel 2 (to Unit 2 Monitor)	2R1B-2
	Unit 2 Control Room Intake Channel 1 (to Unit 2 Monitor)	2R1B-1
	Unit 2 Control Room Intake Channel 2 (to Unit 1 Monitor)	1R1B-2

Immediate action(s), in accordance with the LCO Action Statements, means that the required action should be pursued without delay and in a controlled manner.

(1) The channels listed are required to be operable to meet a single operable channel for the Technical Specificiation's "Minimum Channels Operable" requirement.

(2) The setpoint applies to 1R41D. The measurement range applies to 1R41A and B which display in uCi/cc using the appropriate channel conversion factor from cpm to uCi/cc.

(3) 1R41D is the setpoint channel; 1R41B is the measurement channel.

(4) 1R41D is the setpoint channel; 1R41C is the measurement channel.

(5) The new release rate channel 1R41D setpoint value of 2E4 uCi/sec is within the bounds of the concentration setpoint values listed in Table 3.3-6 (originally for 1R45) for normal and accident plant vent flow rates.

3/4.3.3.2

THIS SECTION DELETED

3/4.3.3.3

THIS SECTION DELETED

3/4.3.3.4

THIS SECTION DELETED

3/4.3.3.5 REMOTE SHUTDOWN INSTRUMENTATION

The OPERABILITY of the remote shutdown instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of HOT STANDBY of the facility from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criteria 19 of 10 CFR 50.

3/4.3.3.6 THIS SECTION DELETED

3/4.3.3.7 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with the Recommendations of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975.

3/4.3.3.8 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The purpose of tank level indicating devices is to assure the detection and control of leaks that if not controlled could potentially result in the transport of radioactive materials to UNRESTRICTED AREAS.

3/4.3.3.9

THIS SECTION DELETED

3/4.3.3.10

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3/4.3.3.14 POWER DISTRIBUTION MONFTORING SYSTEM (PDMS)

The Power Distribution Monitoring System (PDMS) provides core monitoring of the limiting parameters. The PDMS continuous core power distribution measurement methodology begins with the periodic generation of a highly accurate 3-D nodal simulation of the current reactor power distribution. The simulated reactor power distribution is then continuously adjusted by nodal and thermocouple calibration factors derived from an incore power distribution measurement obtained using the incore movable detectors to produce a highly accurate power distribution measurement. The nodal calibration factors are updated at least once every 180 Effective Full Power Days (EFPD). Between calibrations, the fidelity of the measured power distribution is maintained via adjustment to the calibrated power distribution provided by continuously input plant and core condition information. The plant and core condition data utilized by the PDMS is cross checked using redundant information to provide a robust basis for continued operation. The loop inlet temperature is generated by averaging the respective temperatures from each of the loops, excluding any bad data. The core exit thermocouples provide many readings across the core and by the nature of their usage with the PDMS, smoothing of the measured data and elimination of bad data is performed with the Surface Spline fit. PDMS uses the NIS Power Range excore detectors to provide information on the axial power distribution. Hence, the PDMS averages the data from the four Power Range excore detectors and eliminates any bad excore detector data.

The bases for the operability requirements of the PDMS is to provide assurance of the accuracy and reliability of the core parameters measured and calculated by the PDMS core power distribution monitor function. These requirements fall under four categories:

1. Assure an adequate number of operable critical sensors.
2. Assure sufficiently accurate calibration of these sensors.
3. Assure an adequate calibration database regarding the number of data sets.
4. Assure the overall accuracy of the calibration.

The minimum number of required plant and core condition inputs include the following:

1. Control Bank Positions.
2. At least 50% of the cold leg temperatures.
3. At least 75% of the signals from the power range excore detector channels (comprised of top and bottom detector section).
4. Reactor Power Level.
5. A minimum number and distribution of operable core exit thermocouples.
6. A minimum number and distribution of measured fuel assembly power distribution information obtained using the incore movable detectors is incorporated in the nodal model calibration information.

The sensor calibration of Items 1, 2, 3, and 4 above are covered under other specifications. Calibration of the core exit thermocouples is accomplished in two parts. The first being a sensor specific correction to K-type thermocouple temperature indications based on data from a cross calibration of the thermocouple temperature indications to the average RCS temperature measured via the RTDs under isothermal RCS conditions. The second part of the thermocouple calibration is the generation of thermocouple flow mixing factors that cause the radial power distribution measured via the thermocouples to agree with the radial power distribution from a full core flux map measured using the incore movable detectors. This calibration is updated at least once every 180 EFPD.

The operability requirements previously contained in Specification 3.3.3.2 have been moved to UFSAR Section 7.7.2.8 as part of Amendment 282.

3/4.3.4 DELETED

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with all reactor coolant loops in operation, and meet the DNB criterion during all normal operations and anticipated transients. In MODES 1 and 2 with less than all coolant loops in operation, this specification requires that the plant be in at least HOT STANDBY within 1 hour.

In MODE 3, a single reactor coolant loop provides sufficient heat removal for removing decay heat; but, single failure considerations require all loops be in operation whenever the rod control system is energized and at least one loop be in operation when the rod control system is deenergized.

In MODE 4, a single reactor coolant loop or RHR loop provides sufficient heat removal for removing decay heat; but, single failure considerations require that at least 2 loops be OPERABLE. Thus, if the reactor coolant loops are not OPERABLE, this specification requires that two RHR loops be OPERABLE.

In MODE 5, single failure considerations require that two RHR loops be OPERABLE. For support systems: Service Water (SW) and Component Cooling (CC), component redundancy is necessary to ensure no single active component failure will cause the loss of Decay Heat Removal. One piping path of SW and CC is adequate when it supports both RHR loops. The support systems needed before entering into the desired configuration (e.g., one service water loop out for maintenance in Modes 5 and 6) are controlled by procedures, and include the following:

- A requirement that two RHR, two CC and two SW pumps, powered from two different vital buses be kept operable
- A listing of the active (air/motor operated) valves in the affected flow path to be locked open or disabled

Note that four filled reactor coolant loops, with at least two steam generators with at least their secondary side water level greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop. This ensures that a single failure does not cause a loss of decay heat removal.

The operation of one Reactor Coolant Pump or one RHR Pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during Boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with Boron concentration reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump below P-7 with one or more RCS cold legs less than or equal to 312 °F are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by either (1) restricting the water volume in the pressurizer (thereby providing a volume into which the primary coolant can expand, or (2) by restricting the starting of Reactor Coolant Pumps to those times when secondary water temperature in each steam generator is less than 50 °F above each of the RCS cold leg temperatures.

3/4.4.2 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 420,000 pounds per hour of saturated steam at the valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating RHR loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Protection System provides a diverse means of protection against RCS overpressurization at low temperature. While in Mode 5 the safety valve requirement may be met by establishing a vent path of equivalent relieving capacity when no code safety valves are OPERABLE.

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss of load assuming no reactor trip until the first Reactor Protective System trip setpoint is reached (i.e., no credit is taken for a direct reactor trip on the loss of load) and also assuming no operation of the power operated relief valves or steam dump valves.

Demonstration of the safety valves lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code.

Surveillance testing allows a ± 3% lift setpoint tolerance. However, to allow for drift during subsequent operation, the valves must be reset to within ± 1% of the lift setpoint following testing.

3/4.4.3 RELIEF VALVES

The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

A. Manual control of PORVs to control reactor coolant system pressure. This is a function that is used for the steam generator tube rupture accident and for plant shutdown.

B. Automatic control of PORVs to control reactor coolant system pressure. This is a function that reduces challenges to the code safety valves for overpressurization events, including an inadvertent actuation of the Safety Injection System.

C. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

3/4.4.3 RELIEF VALVES (continued)

D. Manual control of the block valve to : (1) unblock an isolated PORV to allow it to be used for manual and automatic control of Reactor Coolant System pressure (Items A & B), and (2) isolate a PORV with excessive seat leakage (Item C).

E. Manual control of a block valve to isolate a stuck-open PORV.

3/4.4.4 PRESSURIZER

The limit on the maximum water volume in the pressurizer assures that the parameter is maintained within the normal steady-state envelope of operation assumed in the SAR. The limit is consistent with the initial SAR assumptions. The 12 hour periodic surveillance is sufficient to assure that the parameter is restored to within its limit following expected transient operation. The maximum water volume also ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that a minimum number of pressurizer heaters be OPERABLE assures that the plant will be able to establish natural circulation.

3/4.4.5 STEAM GENERATOR (SG) TUBE INTEGRITY

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Refueling Outage 18 and the subsequent operating cycle only, the following definition applies: A SG tube is defined as the length of the tube beginning 17 inches from the top of the tubesheet on the tube hot leg side to 17 inches below the top of the tubesheet on the tube cold leg side as defined in LCR S07-01 (including WCAP-16640-P). The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.i, "Steam Generator (SG) Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that significantly affect burst or collapse. In that context, the term "significant" is defined as, "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established."

3/4.4.5 STEAM GENERATOR (SG) TUBE INTEGRITY (Continued)

The determination of whether thermal loads are primary or secondary loads is based on the ASME definition in which secondary loads are self-limiting and will not cause failure under single load application. For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB and draft Reg. Guide 1.121.

The accident induced leakage performance criterion ensures that the primary-to-secondary leakage caused by a design basis accident, other than a steam generator tube rupture (SGTR), is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm per SG. The accident induced leakage rate includes any primary-to-secondary leakage existing prior to the accident in addition to primary-to-secondary leakage induced during the accident.

The operational leakage performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational leakage is contained in LCO 3.4.6.2, "Operational Leakage," and limits primary-to-secondary leakage through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of leakage is due to more than one crack, the cracks are very small, and the above assumption is conservative.

The ACTION requirements are modified by a Note clarifying that the Actions may be entered independently for each SG tube. This is acceptable because the ACTION requirements provide appropriate compensatory actions for each affected SG tube. Complying with the ACTION requirements may allow for continued operation, and subsequent affected SG tubes are governed by subsequent ACTION requirements.

If it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program, an evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. An action time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a

3/4.4.5 STEAM GENERATOR (SG) TUBE INTEGRITY (Continued)

SG tube that may not have tube integrity. If the evaluation determines that the affected tube(s) have tube integrity, plant operation is allowed to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering HOT SHUTDOWN following the next refueling outage or SG inspection. This action time is acceptable since operation until the next inspection is supported by the operational assessment.

If SG tube integrity is not being maintained or the ACTION requirements are not met, the reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within 36 hours. The action times are reasonable based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

During shutdown periods the SGs are inspected as required by surveillance requirements and the Steam Generator Program. NEI 97-06, "Steam Generator Program Guidelines," and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period. The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find existing and potential degradation. Inspection methods are a function of degradation morphology, nondestructive examination (NDE) technique capabilities and inspection locations. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines. The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.8.4.i contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 6.8.4.i are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in size measurement and future growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). NEI 97-06 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria. The Frequency of prior to entering HOT SHUTDOWN following a SG inspection

3/4.4.5 STEAM GENERATOR (SG) TUBE INTEGRITY (Continued)

ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary-to-secondary pressure differential.

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the Reactor Coolant Pressure Boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems", May 1973.

3/4.4.6.2 OPERATIONAL LEAKAGE

Industry experience has shown that while a limited amount of leakage is expected from the RCS, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 GPM. This threshold value is sufficiently low to ensure early detection of additional leakage.

The 10 GPM IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the leakage detection systems.

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

Primary-to-Secondary Leakage Through Any One SG

The primary-to-secondary leakage rate limit applies to leakage through any one Steam Generator. The limit of 150 gallons per day per steam generator is based on the operational leakage performance criterion in NEI 97-06, Steam Generator Program Guidelines. The Steam Generator Program operational leakage performance criterion in NEI 97-06 states, "The RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with steam generator tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator program is an effective measure for minimizing the frequency of steam generator tube ruptures.

Actions

Unidentified leakage or identified leakage in excess of the LCO limits must be reduced to within limits within 4 hours. This action time allows time to verify leakage rates and either identify unidentified leakage or reduce leakage to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the reactor coolant pressure boundary (RCPB). If any pressure boundary leakage exists, or primary-to-secondary leakage is not within limit, or if unidentified or identified leakage cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the leakage and

3/4.4.6.2 OPERATIONAL LEAKAGE (Continued)

its potential consequences. It should be noted that leakage past seals and gaskets is not pressure boundary leakage. The reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within 36 hours. This action reduces the leakage and also reduces the factors that tend to degrade the pressure boundary. The action times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In COLD SHUTDOWN, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

Surveillances

Verifying RCS leakage to be within the LCO limits ensures the integrity of the Reactor Coolant Pressure Boundary is maintained. Pressure boundary leakage would at first appear as unidentified leakage and can only be positively identified by inspection. It should be noted that leakage past seals and gaskets is not pressure boundary leakage. Unidentified leakage and identified leakage are determined by performance of an RCS water inventory balance. The RCS water inventory must be met with the reactor at steady state conditions. The surveillance is modified by a Note that the surveillance is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational leakage determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows. The 72 hour frequency is a reasonable interval to trend leakage and recognizes the importance of early leakage detection in the prevention of accidents.

Mode ascension to MODE 1-3 is acceptable without a current RCS Inventory Balance, provided the asterisked note of "Not required to be completed until 12 hours after establishment of steady state operations", is complied with.

Satisfying the primary-to-secondary leakage limit ensures that the operational leakage performance criterion in the Steam Generator Program is met. If SR 4.4.6.2.c is not met, compliance with LCO 3.4.5, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature (in accordance with EPRI PWR Primary-to-Secondary Leak Guidelines). If it is not practical to assign the leakage to an individual steam generator, all the primary-to-secondary leakage should be conservatively assumed to be from one Steam Generator. The Surveillance is modified by a Note which states that the surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary-to-secondary leakage determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows. The Surveillance Frequency of 72 hours is a reasonable interval to trend primary-to-secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling (in accordance with EPRI PWR Primary-to-Secondary Leak Guidelines).

3/4.4.7

THIS SECTION DELETED

3/4.4.8 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the resulting 2 hour doses at the site boundary will not exceed an appropriately small fraction of Part 100 limits following a steam generator tube rupture accident in conjunction with an assumed steady state primary-to-secondary steam generator leakage rate of 1.0 GPM. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters of the Salem site, such as site boundary location and meteorological conditions, were not considered in this evaluation. The NRC is finalizing site specific criteria which will be used as the basis for the reevaluation of the specific activity limits of this site. This reevaluation may result in higher limits.

Reducing T_{avg} to <500°F prevents the release of activity should a steam generator tube rupture occur since the saturation pressure of the primary coolant is below the lift pressure of the atmospheric steam relief valves. The surveillance requirements provide adequate assurance that excessive specific activity levels in the primary coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

LCO 3.0.4.c is applicable. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS.

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G.

1) The reactor coolant temperature and pressure and system heatup and cooldown rate (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 and 3.4-3 for the service period specified thereon.

   a) Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation.

   b) Figures 3.4-2 and 3.4-3 define limits to assure prevention of nondoctile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

2) These limit lines shall be calculated periodically using methods provided below.

3) The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F.

4) The pressurizer heatup and cooldown rates shall not exceed 100°F/hr and 200°F/hr, respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

5) System preservice hydrotests and in-service leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, ASTM E185-82, and in accordance with additional reactor vessel requirements. These properties are then evaluated in accordance with Appendix G of the 1996 Summer Addenda to Section XI of the ASME Boiler and Pressure Vessel Code and the calculation methods described in WCAP-14040-NP-A, Rev. 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves", January 1996, and ASME Boiler and Pressure Vessel Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves for Section XI, Division 1", approved March 1999.

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RT_{NDT}, at the end of 32 effective full power years of service life. The 32 EFPY service life period is chosen such that the limiting RT_{NDT} at the 1/4T location in the core region is greater than the RT_{NDT} of the limiting unirradiated material. The selection of such a limiting RT_{NDT} assures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Table B 3/4.4-1. Reactor operation and resultant fast neutron (E greater than 1 MeV) irradiation can cause an increase in the RT_{NDT}. An adjusted reference temperature, (ART), based upon the fluence and the copper and nickel content of the material in question, can be predicted.

The ART is based upon the largest value of RT_{NDT} computed by the methodology presented in Regulatory Guide 1.99, Revision 2. The ART for each material is given by the following expression:

$$ART = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin}$$

Initial RT_{NDT} is the reference temperature for the unirradiated material. ΔRT_{NDT} is the mean value of the adjustment in reference temperature caused by the irradiation and is calculated as follows:

$$\Delta RT_{NDT} = \text{Chemistry Factor} \times \text{Fluence Factor}$$

The Chemistry Factor, CF(F), is a function of copper and nickel content. It is given in Table B3/4.4-2 for welds and in Table B3/4.4-3 for base metal (plates and forgings). Linear interpolation is permitted.

The predicted neutron fluence as a function of Effective Full Power Years (EFPY) has been calculated and is shown in Figure B3/4.4-1. The fluence factor can be calculated by using Figure B3/4.4-2. Also, the neutron fluence at any depth in the vessel wall is determined as follows:

$$f = (f\ \text{surface}) \times (e^{-0.24X})$$

where "f surface" is from Figure B3/4.4-1, and X (in inches) is the depth into the vessel wall.

Finally, the "Margin" is the quantity in °F that is to be added to obtain conservative, upper-bound values of adjusted reference temperature for the calculations required by Appendix G to 10 CFR Part 50.

$$\text{Margin} = 2\sqrt{\sigma_I^2 + \sigma_\Delta^2}$$

If a measured value of initial RT_{NDT} for the material in question is used, σ_I may be taken as zero. If generic value of initial RT_{NDT} is used, σ_I, should be obtained from the same set of data. The standard deviations, for ΔRT_{NDT}, σ_Δ, are 28°F for welds and 17°F for base metal, except that σ_Δ need not exceed 0.50 times the mean value of ΔRT_{NDT} surface.

The heatup and cooldown limit curves of Figures 3.4-2 and 3.4-3 include predicted adjustments for this shift in RT_{NDT} at the end of 32 EFPY.

Values of ΔRT_{NDT} determined in this manner may be used until the results from the material surveillance program, evaluated according to ASTM E185, are available. Capsules will be removed in accordance with the requirements of ASTM E185-82 and 10 CFR Part 50, Appendix H. The heatup and cooldown curves must be recalculated when the ΔRT_{NDT} determined from the surveillance capsule exceeds the calculated ΔRT_{NDT} for the equivalent capsule radiation exposure.

Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Appendix G in Section XI of the ASME Boiler and Pressure Vessel Code as required by Appendix G to 10 CFR Part 50 and these methods are discussed in detail in WCAP-14040-NP-A, Rev. 2, ''Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves'', January 1996, and ASME Boiler and Pressure Vessel Code Case N-640, " Alternative Reference Fracture Toughness for Development of P-T Limit Curves for Section XI, Division 1" , approved March 1999.

The general method for calculating heatup and cooldown limit curves is based upon the principles of the linear elastic fracture mechanics (LEFM) technology. In the calculation procedures a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, T, and a length of 3/2T is assumed to exist at the inside of the vessel wall as well as at the outside of the vessel wall. The dimensions of this postulated crack, referred to in Appendix G of ASME Section XI as the reference flaw, amply exceed the current capabilities of inservice inspection techniques. Therefore, the reactor operation limit curves developed for this reference crack are conservative and provide sufficient safety margins for protection against nonductile failure. To assure that the radiation embrittlement effects are accounted for in the calculation of the limit curves, the most limiting value of the nil-ductility reference temperature, RT_{NDT}, is used and this includes the radiation induced shift, ΔRT_{NDT} corresponding to the end of the period for which heatup and cooldown curves are generated.

The ASME approach for calculating the allowable limit curves for various heatup and cooldown rates specifies that the total stress intensity factor, K_I, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, K_{IC}, for the metal temperature at that time. K_{IC} is obtained from the reference fracture toughness curve, defined in ASME Code Case N-640. The K_{IC} curve is given by the equation:

$$K_{IC} = 33.2 + 20.734 \exp [0.02(T-RT_{NDT})] \qquad (1)$$

where K_{IC} is the reference stress intensity factor as a function of the metal temperature T and the metal nil-ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\ K_{IM} + K_{IT} \leq K_{IC} \qquad (2)$$

where K_{IM} is the stress intensity factor caused by membrane (pressure) stress.

K_{IT} is the stress intensity factor caused by the thermal gradients.

K_{IC} is provided by the code as a function of temperature relative to the RT_{NDT} of the material.

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{IC} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding (thermal) stress intensity factors, K_{IT}, for the reference flaw are computed. From Equation (2) the pressure stress intensity factors are obtained and from these the allowable pressures are calculated.

COOLDOWN

For the calculation of the allowable pressure versus coolant temperature during cooldown, the Code reference flaw is assumed to exist at the inside of the vessel wall. During cooldown, the controlling location of the flaw is always at the inside of the wall because the thermal gradients produce tensile stresses at the inside, which increase with increasing cooldown rates. Allowable pressure-temperature relations are generated for both steady-state and finite cooldown rate situations. From these relations composite limit curves are constructed for each cooldown rate of interest.

The use of the composite curve in the cooldown analysis is necessary because control of the cooldown procedure is based on measurement of reactor coolant temperature, whereas the limiting pressure is actually dependent on the material temperature at the tip of the assumed flaw. During cooldown, the 1/4T vessel location is at a higher temperature than the fluid adjacent to the vessel ID. This condition, of course, is not true for the steady-state situation. It follows that at any given reactor coolant temperature, the ΔT developed during cooldown results in a higher value of K_{IC} at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if conditions exist such that the increase in K_{IC} exceeds K_{IT}, the calculated allowable pressure during cooldown will be greater than the steady-state value.

The above procedures are needed because there is no direct control on temperature at the 1/4T location, therefore, allowable pressures may unknowingly be violated if the rate of cooling is decreased at various intervals along a cooldown ramp. The use of the composite curve eliminates this problem and assures conservative operation of the system for the entire cooldown period.

HEATUP

Three separate calculations are required to determine the limit curves for finite heatup rates. As is done in the cooldown analysis, allowable pressure-temperature relationships are developed for steady-state conditions as well as finite heatup rate conditions assuming the presence of a 1/4T defect at the inside of the vessel wall. The thermal gradients during heatup produce compressive stress at the inside of the wall that alleviate the tensile stresses produced by internal pressure. The metal temperature at the crack tip lags the coolant temperature therefore, the K_{IC} for the 1/4T crack during heatup is lower than the K_{IC} for the 1/4T crack during steady-state conditions at the same coolant temperature. During heatup, especially at the end of the transient, conditions may exist such that the effects of compressive thermal stresses and different K_{IC}s for steady-state and finite heatup rates do not offset each other and the pressure-temperature curve based on steady-state conditions no longer represents a lower bound of all similar curves for finite heatup rates when the 1/4T flaw is considered. Therefore, both cases have to be analyzed in order to assure that at any coolant temperature the lower value of the allowable pressure calculated for steady-state and finite heatup rates is obtained.

The second portion of the heatup analysis concerns the calculation of pressure-temperature limitations for the case in which a 1/4T deep outside surface flaw is assumed. Unlike the situation at the vessel inside surface, the thermal gradients established at the outside surface during heatup produce stresses which are tensile in nature and thus tend to reinforce any pressure stresses present. These thermal stresses, of course, are dependent on both the rate of heatup and the time (or coolant temperature) along the heatup ramp. Furthermore, since the thermal stresses, at the outside are tensile and increase with increasing heatup rate, a lower bound curve cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

Following the generation of pressure-temperature curves for both the steady-state and finite heatup rate situations, the final limit curves are produced as follows. A composite curve is constructed based on a point-by-point comparison of the steady-state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the three values taken from the curves under consideration.

The use of the composite curve is necessary to set conservative heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling condition switches from the inside to the outside and the pressure limit must at all times be based on analysis of the most critical criterion.

Finally, the new 10CFR50 rule which addresses the metal temperature of the closure head flange is considered. This 10CFR50 rule states that the metal temperature of the closure flange regions must exceed the material RT_{NDT} by at least 120° F for normal operation when the pressure exceeds 20 percent of the preservice hydrostatic test pressure (621 psig for Salem). Table B3/4 4-1 indicates that the limiting RT_{NDT} of 28° F occurs in the closure head flange of Salem Unit 1, and the minimum allowable temperature of this region is 148° F at pressures greater than 621 psig. These limits do not affect Figures 3.4-2 and 3.4-3.

Although the pressurizer operates in temperature ranges above those for which there is reason for concern of non-ductile failure, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Code requirements.

The OPERABILITY of two POPS or an RCS vent opening of greater than 3.14 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 312°F. Either POPS has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 50° F above the RCS cold leg temperatures, or (2) the start of an intermediate head safety injection pump and its injection into a water solid RCS, or the start of a high head safety injection pump in conjunction with a running positive displacement pump and its injection into a water solid RCS. The minimum electrical power sources required to assure POPS operability (based on POPS meeting the single failure criteria) consist of a normal (via offsite power) and an emergency (via batteries) power source for each train of POPS. Emergency diesel generators are not required for POPS to meet single failure criteria and therefore are not required for POPS OPERABILITY.

LCO 3.0.4.b is not applicable to an inoperable LTOP system when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable LTOP system. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

TABLE B 3/4.4-1
SALEM UNIT 1 REACTOR VESSEL TOUGHNESS DATA

Component	Plate No. or Weld No.	Material Type	Cu (%)	Ni (%)	T (°F)	50 ft lb 35-Mil Temp (°F)	RT (°F)	Average Upper Shelf Energy: Normal to Principal Working Direction (ft-lb)	Average Upper Shelf Energy: Principal Working Direction (ft-lb)
Cl Hd Dome	B2407-1	A533B, Cl.1	0.20	0.50	-30	99*	39	71.5*	110
Cl Hd Segment	B2406-1	A533B, Cl.1	0.13	0.52	-20	89*	29	97*	125
Cl Hd Segment	B2406-2	A533B, Cl.1	0.16	0.50	-30	85*	25	79*	122
Cl Hd Segment	B2406-3	A533B, Cl.1	0.10	0.53	-50	66*	6	86*	132
Cl Hd Flange	B2811	A508, Cl.2	-	0.72	28*	22*	28	129*	199
Vessel Flange	B2410	A508, Cl.2	-	0.67	60*	0*	60	94*	145
Inlet Nozzle	B2408-1	A508, Cl.2	-	0.68	50*	43*	50	94*	144
Inlet Nozzle	B2408-2	A508, Cl.2	-	0.71	46*	26*	46	102*	157
Inlet Nozzle	B2408-3	A508, Cl.2	-	0.66	47*	37*	47	105*	161
Inlet Nozzle	B2408-4	A508, Cl.2	-	0.65	9*	17*	9	108.5*	167
Outlet Nozzle	B2409-1	A508, Cl.2	-	0.69	60*	95*	60	48*	75
Outlet Nozzle	B2409-2	A508, Cl.2	-	0.69	60*	95*	60	51*	78
Outlet Nozzle	B2409-3	A508, Cl.2	-	0.74	60*	10*	60	79*	121
Outlet Nozzle	B2409-4	A508, Cl.2	-	0.74	60*	13*	60	82*	126
Upper Shell	B2401-1	A533B, Cl.1	0.22	0.48	-30	87*	27	74*	114
Upper Shell	B2401-2	A533B, Cl.1	0.19	0.48	0	80*	20	79*	122
Upper Shell	B2401-3	A533B, Cl.1	0.24	0.51	-10	114*	34	62*	96
Inter Shell	B2402-1	A533B, Cl.1	0.24	0.53	-30	105	45	91	97
Inter Shell	B2402-2	A533B, Cl.1	0.24	0.53	-30	55	-5	98	112
Inter Shell	B2402-3	A533B, Cl.1	0.22	0.51	-40	57	-3	104	127
Lower Shell	B2403-1	A533B, Cl.1	0.19	0.48	-40	70	4	93	143
Lower Shell	B2403-2	A533B, Cl.1	0.19	0.49	-70	86	18	83	128
Lower Shell	B2403-3	A533B, Cl.1	0.19	0.48	-40	90	6	85	131
Bot Hd Segment	B2404-1	A533B, Cl.1	0.10	0.52	10	48*	10	78*	120
Bot Hd Segment	B2404-2	A533B, Cl.1	0.11	0.53	-50	60*	0	86*	132
Bot Hd Segment	B2404-3	A533B, Cl.1	0.12	0.52	10	47*	10	82*	126
Bot Hd Dome	B2405-1	A533B, Cl.1	0.15	0.50	-20	57*	-3	69*	106
Circum Weld Bet Nozzle Shell & Int. Shell	8-042	-	0.22	1.02	-	-	-56***	-	-
Circum Weld Bet. Int. and Lower Shell	9-042	-	0.22	0.73	-	-	-56***	112	-
Int. Shell Vertical Weld	2-042 [A,B,C]	-	0.18	1.04	-	-	-56***	96.2	-
Lower Shell Vertical Weld	3-042 [A,B,C]	-	0.19	1.04	-	-	-56***	112	-

* Estimated per NRC Standard Review Plan Section 5.3.2.
*** Estimated per Pressurized Thermal Shock Rule, 10 CFR 50.61

TABLE B 3/4.4.2

CHEMISTRY FACTOR FOR WELDS, °F

Copper, Wt-%	Nickel, Wt-% 0	0.20	0.40	0.60	0.80	1.00	1.20
0	20	20	20	20	20	20	20
0.01	20	20	20	20	20	20	20
0.02	21	26	27	27	27	27	27
0.03	22	35	41	41	41	41	41
0.04	24	43	54	54	54	54	54
0.05	26	49	67	68	68	68	68
0.06	29	52	77	82	82	82	82
0.07	32	55	85	95	95	95	95
0.08	36	58	90	106	108	108	108
0.09	40	61	94	115	122	122	122
0.10	44	65	97	122	133	135	135
0.11	49	68	101	130	144	148	148
0.12	52	72	103	135	153	161	161
0.13	58	76	106	139	162	172	176
0.14	61	79	109	142	168	182	188
0.15	66	84	112	146	175	191	200
0.16	70	88	115	149	178	199	211
0.17	75	92	119	151	184	207	221
0.18	79	95	122	154	187	214	230
0.19	83	100	126	157	191	220	238
0.20	88	104	129	160	194	223	245
0.21	92	108	133	164	197	229	252
0.22	97	112	137	167	200	232	257
0.23	101	117	140	169	203	236	263
0.24	105	121	144	173	206	239	268
0.25	110	126	148	176	209	243	272
0.26	113	130	151	180	212	246	276
0.27	119	134	155	184	216	249	280
0.28	122	138	160	187	218	251	284
0.29	128	142	164	191	222	254	287
0.30	131	146	167	194	225	257	290
0.31	136	151	172	198	228	260	293
0.32	140	155	175	202	231	263	296
0.33	144	160	180	205	234	266	299
0.34	149	164	184	209	238	269	302
0.35	153	168	187	212	241	272	305
0.36	158	172	191	216	245	275	308
0.37	162	177	196	220	248	278	311
0.38	166	182	200	223	250	281	314
0.39	171	185	203	227	254	285	317
0.40	175	189	207	231	257	288	320

TABLE B 3/4.4-3

CHEMISTRY FACTOR FOR BASE METAL, °F

Copper, Wt-%	Nickel, Wt-% 0	0.20	0.40	0.60	0.80	1.00	1.20
0	20	20	20	20	20	20	20
0.01	20	20	20	20	20	20	20
0.02	20	20	20	20	20	20	20
0.03	20	20	20	20	20	20	20
0.04	22	26	26	26	26	26	26
0.05	25	31	31	31	31	31	31
0.06	28	37	37	37	37	37	37
0.07	31	43	44	44	44	44	44
0.08	34	48	51	51	51	51	51
0.09	37	53	58	58	58	58	58
0.10	41	58	65	65	67	67	67
0.11	45	62	72	74	77	77	77
0.12	49	67	79	83	86	86	86
0.13	53	71	85	91	96	96	96
0.14	57	75	91	100	106	106	106
0.15	61	80	99	110	115	117	117
0.16	65	84	104	118	123	125	125
0.17	69	88	110	127	132	135	135
0.18	73	92	115	134	141	144	144
0.19	78	97	120	142	150	154	154
0.20	82	102	125	149	159	164	165
0.21	86	107	129	155	167	172	174
0.22	91	112	134	161	176	181	184
0.23	95	117	138	167	184	190	194
0.24	100	121	143	172	191	199	204
0.25	104	126	148	176	199	208	214
0.26	109	130	151	180	205	216	221
0.27	114	134	155	184	211	225	230
0.28	119	138	160	187	218	233	239
0.29	124	142	164	191	221	241	248
0.30	129	146	167	194	225	249	257
0.31	134	151	172	198	228	255	266
0.32	139	155	175	202	231	260	274
0.33	144	160	180	205	234	264	282
0.34	149	164	184	209	238	268	290
0.35	153	168	187	212	241	272	298
0.36	158	173	191	216	245	275	303
0.37	162	177	196	220	248	278	308
0.38	166	182	200	223	250	281	313
0.39	171	185	203	227	254	285	317
0.40	175	189	207	231	257	288	320

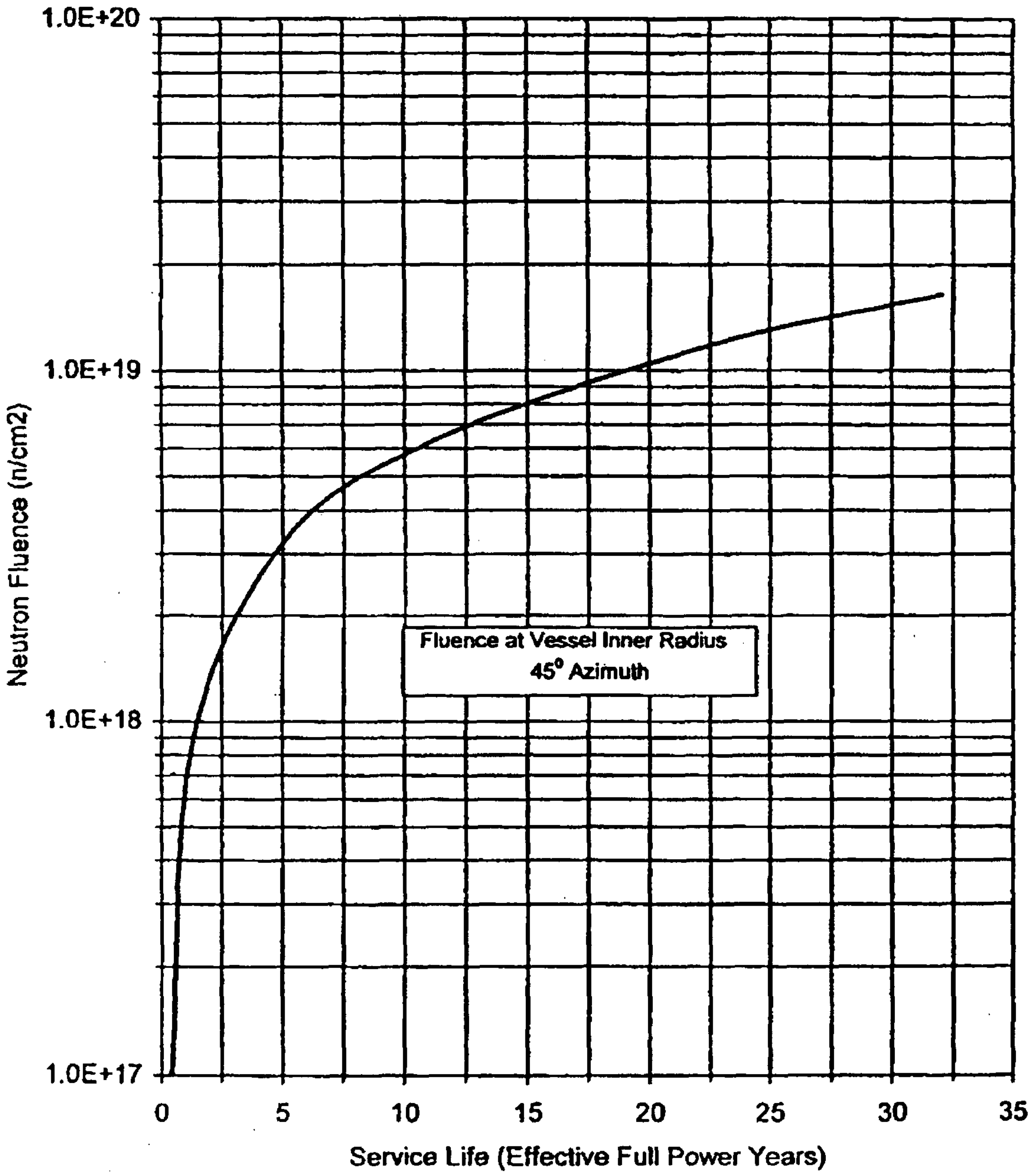
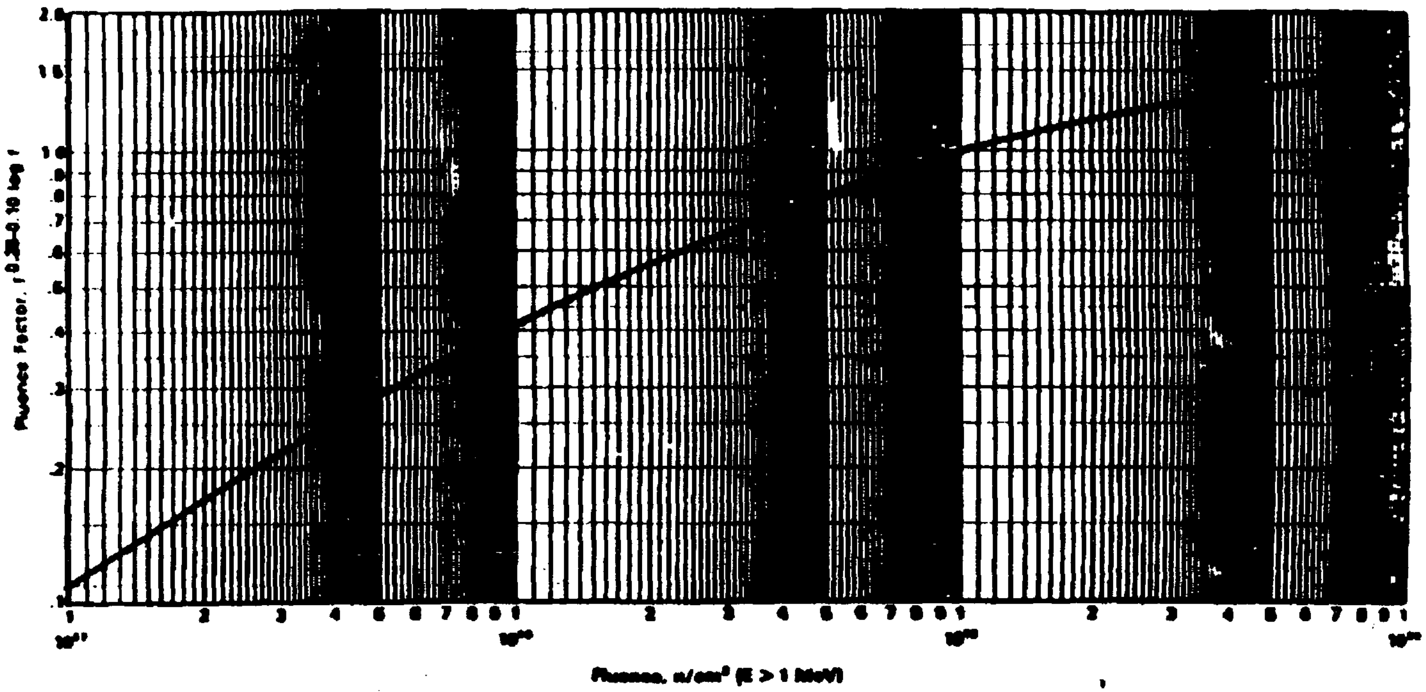


Figure B 3/4.4-1 Fast neutron fluence (E>1MeV) as a function of full power service life (EFPY)



Fluence factor for use in the expression for ΔRT_{NDT}

FIGURE B 3/4 4-2

3/4.4.10 STRUCTURAL INTEGRITY

The inspection programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant. To the extent applicable, the inspection program for these components is in compliance with Section XI of the ASME Boiler and Pressure Vessel Code.

3/4.4.11 THIS SECTION INTENTIONALLY BLANK

3/4.4.12 REACTOR VESSEL HEAD VENTS

Reactor Coolant System vents are provided to exhaust noncondensible gases and/or steam from the Reactor Coolant System that could inhibit natural circulation core cooling. The OPERABILITY of a reactor vessel head vent path ensures the capability exists to perform this function.

The valve redundancy of the Reactor Coolant System vent paths serves to minimize the probability of inadvertant or irreversible actuation while ensuring that a single failure in a vent valve power supply or control system does not prevent isolation of the vent path.

The function, capabilities, and testing requirements of the Reactor Coolant System Vent Systems are consistent with the requirements of Item II.B.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Correction letter dated February 15, 1990, to Amendment 108 dated January 29, 1990.

3/4.5.1 ACCUMULATORS

The OPERABILITY of each RCS accumulator ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the accumulators. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

The limits on accumulator volume, boron concentration and pressure ensure that the assumptions used for accumulator injection in the safety analysis are met.

The accumulator power operated isolation valves are considered to be "operating bypasses" in the context of IEEE Std. 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required.

The limits for operation with an accumulator inoperable for any reason except an isolation valve closed minimizes the time exposure of the plant to a LOCA event occurring concurrent with failure of an additional accumulator which may result in unacceptable peak cladding temperatures. If a closed isolation valve cannot be immediately opened, the full capability of one accumulator is not available and prompt action is required to place the reactor in a mode where this capability is not required.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the accumulators is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double ended break of the largest RCS cold leg pipe downward. In addition, each ECCS subsystem provides long term core cooling capability in the recirculation mode during the accident recovery period.

The limitation for a maximum of one safety injection pump or centrifugal charging pump to be OPERABLE and the Surveillance Requirement to verify all safety injection pumps except the allowed OPERABLE pump to be inoperable below 312°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single POPs relief valve.

When running a safety injection pump with the RCS temperature less than 312 °F with the potential for injecting into the RCS and creating a mass addition pressure transient, two independent means of preventing reactor coolant system injection will be utilized. The two independent means can be satisfied by any one of the following methods:
(1) A manual isolation valve locked in the closed position; or
(2) Two manual isolation valves closed; or
(3) One motor operated valve closed and its breaker de-energized and control circuit fuses removed; or
(4) One air operated valve closed and its air supply maintained in such a manner as to ensure that the valve will remain closed.

ECCS SUBSYSTEMS (Continued)

With the RCS temperature below 350°F, one OPERABLE ECCS subsystem is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

The surveillance requirements, which are provided to ensure the OPERABILITY of each component, ensure that, at a minimum, the assumptions used in the safety analysis are met and that subsystem OPERABILITY is maintained. The safety analyses make assumptions with respect to: 1) both the maximum and minimum total system resistance, and 2) both the maximum and minimum branch injection line resistance. These resistances, in conjunction with the ranges of potential pump performance, are used to calculate the maximum and minimum ECCS flow assumed in the safety analyses.

The maximum and minimum flow surveillance requirements in conjunction with the maximum and minimum pump performance curves ensures that the assumptions of total system resistance and the distribution of that system resistance among the various paths are met.

The maximum total pump flow surveillance requirements ensure the pump runout limits of 560 gpm for the centrifugal charging pumps and 675 gpm for the safety injection pumps are not exceeded.

The surveillance requirement for the maximum difference between the maximum and minimum individual injection line flows ensure that the minimum individual injection line resistance assumed for the spilling line following a LOCA is met.

LCO 3.0.4.b is not applicable to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystem. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

ECCS SUBSYSTEMS (Continued)

With the RCS temperature below 350°F, one OPERABLE ECCS subsystem is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

The surveillance requirements, which are provided to ensure the OPERABILITY of each component, ensure that, at a minimum, the assumptions used in the safety analysis are met and that subsystem OPERABILITY is maintained. The safety analyses make assumptions with respect to: 1) both the maximum and minimum total system resistance, and 2) both the maximum and minimum branch injection line resistance. These resistances, in conjunction with the ranges of potential pump performance, are used to calculate the maximum and minimum ECCS flow assumed in the safety analyses.

The maximum and minimum flow surveillance requirements in conjunction with the maximum and minimum pump performance curves ensures that the assumptions of total system resistance and the distribution of that system resistance among the various paths are met.

The maximum total pump flow surveillance requirements ensure the pump runout limits of 560 gpm for the centrifugal charging pumps and 675 gpm for the safety injection pumps are not exceeded. Due to the effect of pump suction boost alignment, the runout limits for the surveillance critéria are ≤ 554 gpm for C/SI pumps, ≤ 664 gpm for SI pumps in cold leg alignment, and ≤ 654 gpm for SI pumps in hot leg alignment.

The surveillance requirement for the maximum difference between the maximum and minimum individual injection line flows ensure that the minimum individual injection line resistance assumed for the spilling line following a LOCA is met.

3/4.5.4 SEAL INJECTION FLOW

The Reactor Coolant Pump (RCP) seal injection flow restriction limits the amount of ECCS flow that would be diverted from the injection path following an ECCS actuation. This limit is based on safety analysis assumptions, since RCP seal injection flow is not isolated during Safety Injection (SI).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. Line pressure and flow must be known to establish the proper line resistance. Flow line resistance is determined by assuming that the RCS pressure is at normal operating pressure, and that the centrifugal charging pump discharge pressure is greater than or equal to 2430 psig. Charging pump header pressure is used instead of RCS pressure, since it is more representative of flow diversion during an accident. The additional LCO modifier, charging flow control valve full open, is required since the valve is designed to fail open. With the LCO specified discharge pressure and control valve position, a flow limit is established. This flow limit is used in the accident analysis.

A provision has been added to exempt surveillance requirement 4.0.4 for entry into MODE 3, since the surveillance cannot be performed in a lower mode The exemption is permitted for up to 4 hours after the RCS pressure has stabilized within ± 20 psig of normal operating pressure. The RCS pressure requirement produces the conditions necessary to correctly set the manual throttle valves. The exemption is limited to 4 hours to ensure timely surveillance completion once the necessary conditions are established.

3/4.5.5 REFUELING WATER STORAGE TANK

The OPERABILITY of the RWST as part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA.

The limits on RWST minimum volume and boron concentration ensure that: (1) sufficient water is available within containment to permit recirculation cooling flow to the core, (2) the reactor will remain subcritical in the cold condition following a small LOCA assuming complete mixing of the RWST, RCS, and ECCS water volumes with all control rods inserted except the most reactive control assembly (ARI-1), and (3) the reactor will remain subcritical in the cold condition following a large break LOCA (break flow area > 3.0 sq. ft.) assuming complete mixing of the RWST, RCS, and ECCS water and other sources of water that may eventually reside in the sump following a LOCA with all control rods assumed to be out (ARO).

The limits on contained water volume and boron concentration also ensure a pH value of between 7.0 and 10.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.6.1 PRIMARY CONTAINMENT

3/4 6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR 100 during accident conditions.

The purpose of this surveillance requirement (4.6.1.1a) is not to perform any testing or valve manipulations, but to verify that containment isolation valves capable of being mispositioned are in their proper safety position (closed).

Physical verification (hands on verification) that these penetrations (containment isolation valves) are in the proper position is performed prior to entering Mode 4 from Mode 5 and documented in the appropriate valve line-up. Allowing the use of administrative means to verify compliance with the surveillance requirement for these valves is acceptable based on the limited access to these areas in Modes 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified in the proper position, is small.

The service water accumulator vessel and discharge valves function to maintain water filled, subcooled fluid conditions in the containment fan coil unit (CFCU) cooling loops during accident conditions. The service water accumulator vessel and discharge valves were installed to address the Generic Letter 96-06 issues of column separation waterhammer and two phase flow during an accident involving a loss of offsite power. The operability of each service water accumulator vessel and discharge valve is required to ensure the integrity of containment penetrations associated with the containment fan coil units during accident conditions. If a service water accumulator vessel does not meet the vessel surveillance requirements, or if the discharge valve response time does not meet design acceptance criteria when tested in accordance with procedures, the containment integrity requirements of the CFCU cooling loops exclusively supplied by the inoperable accumulator vessel or discharge valve are not met. Limiting Condition for Operation 3.6.1.1 is applicable, and the cooling loops for the two CFCU's exclusively supplied by the inoperable accumulator are to be removed from service and isolated to maintain containment integrity.

3/4 6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure P_a. As an added conservatism, the measured overall integrated leakage rate (Type A test) is further limited to less than or equal to 0.75 L_a or less than or equal to 0.75 L_t, as applicable, during performance of the periodic test to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the Containment Leakage Rate Testing Program.

3/4.6.1.3 CONTAINMENT AIR LOCKS

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 feet in diameter, with a door at each end. The doors are interlocked during normal operation to prevent simultaneous opening.

During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure-seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock door interlock mechanism is defeated.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident. In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day. This leakage rate is defined in 10CFR50, Appendix J as L_a = 0.1% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 47.0 psig following a DBA. The allowable leakage rate forms the basis for the acceptance criteria imposed on the surveillance requirements associated with the air locks.

Each containment air lock forms part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from containment.

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment Building Penetrations".

The ACTIONS are modified by five notes. Note (1) allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock.

However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

Note (2) adds clarification that separate condition entry is allowed for each air lock. This is acceptable, since the required ACTIONS provide appropriate compensatory measures for each inoperable air lock. Complying with the Required Actions may allow for continued operation. A subsequent inoperable air lock is governed by condition entry for that air lock.

Notes (3) and (4) ensure that only the required ACTIONS and associated completion times of condition c. are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required ACTIONS c.1 and c.2 are the appropriate remedial actions. The exception of these Notes does not affect tracking the completion time from the initial entry into condition a., only the requirement to comply with the required ACTIONS.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note (5) directs entry into the applicable Conditions and required ACTIONS of LCO 3.6.1, "Primary Containment."

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (ACTION a.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This ACTION must be completed within 1 hour. The specified time period is consistent with the ACTIONS of LCO 3.6.1.1 that requires that containment be restored to OPERABLE status within 1 hour. OPERABILITY of the air lock interlock is not required to support the OPERABILITY of an air lock door.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour completion time (ACTION a.2). The 24 hour completion time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required ACTION a.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The completion time of once per 31 days is based on engineering judgement and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls.

ACTION a.3 allows the use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7-day restriction begins when the second air lock is discovered to be inoperable. Containment entry may be required on a periodic basis to perform Technical Specification Surveillances and required ACTIONS, as well as other activities on equipment inside containment that are required by Technical Specifications or activities on equipment that support Technical Specification required equipment. This Note is not intended to preclude performing other activities (i.e., non-Technical Specification required activities) if the containment is entered, using the inoperable air lock, to perform an allowed entry listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

Because of ALARA considerations, ACTION a.3 also allows air lock doors located in high radiation areas to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

With an air lock interlock mechanism inoperable in one or more air locks, the required ACTIONS and associated completion times are consistent with those specified in Condition a. In addition, ACTION b.3 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock). In addition, ACTION b.3 allows air lock doors located in high radiation areas to be verified locked closed by use of administrative means.

ACTION c.1 requires that with one or more air locks inoperable for reasons other than those described in condition a. or b., action must be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required ACTION c.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour completion time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour completion time. This completion time begins at the time that the air lock is discovered to be inoperable. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

If the inoperable containment air lock cannot be restored to OPERABLE status within the required completion time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least Hot Standby within 6 hours and to Cold Shutdown within the following 30 hours. The allowed completion times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Maintaining containment airlocks OPERABLE requires compliance with the leakage rate test requirements of 10CFR50, Appendix J, as modified by approved exemptions. This Surveillance Requirement reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The frequency is required by Appendix J, as modified by approved exemptions. Thus, the provision of Specification 4.0.2 (which allows frequency extensions) does not apply.

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when the containment air lock door is opened, this test is only required to be performed upon entering or exiting a containment air lock but is not required more frequently than every six months. The six-month frequency is based on engineering judgement and is considered adequate in view of other indications of door and interlock mechanism status available to operations personnel.

3/4.6.1.4 INTERNAL PRESSURE

The limitations on containment internal pressure ensure that: 1) the containment structure is prevented from exceeding its design negative pressure differential with respect to the outside atmosphere of 3.5 psig and 2) the containment peak pressure does not exceed the design pressure of 47 psig during the limiting pipe break conditions. The pipe breaks considered are LOCA and steam line breaks.

The limit of 0.3 psig for initial positive containment pressure is consistent with the accident analyses initial conditions.

The maximum peak pressure expected to be obtained from a LOCA or steam line break event is $\leq$ 47 psig.

3/4.6.1.5 AIR TEMPERATURE

The limitations on containment average air temperature ensure that the overall containment average air temperature does not exceed the initial temperature condition assumed in the accident analysis for a LOCA or steam line break. In order to determine the containment average air temperature, an average is calculated using measurements taken at locations within containment selected to provide a representative sample of the overall containment atmosphere.

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the containment will withstand the design pressure. The visual inspections of the concrete and liner and the Type A leakage test both in accordance with the Containment Leakage Rate Testing Program are sufficient to demonstrate this capability.

(Note that the elements of 3/4.6.1.7 were RELOCATED to 3/4 6.3 by LCR S06-06)

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the containment spray system, when operated in conjunction with the Containment Cooling System, ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

Normal plant operation and maintenance practices are not expected to trigger surveillance requirement 4.6.2.1.d. Only an unanticipated circumstance would initiate this surveillance, such as inadvertent spray actuation, a major configuration change, or a loss of foreign material control when working within the affected boundary of the system. If an activity occurred that presents the potential of creating nozzle blockage, an evaluation would be performed by the engineering organization to determine if the amount of nozzle blockage would impact the required design capabilities of the containment spray system. If the evaluation determines that the containment spray system would continue to perform its design basis function, then performance of the air or smoke flow test would not be required. If the evaluation cannot conclusively determine the impact to the containment spray system, then the air or smoke flow test would be performed to determine if any nozzle blockage has occurred.

3/4.6.2.2 SPRAY ADDITIVE SYSTEM

The OPERABILITY of the spray additive system ensures that sufficient NaOH is added to the containment spray in the event of a LOCA. The limits on NaOH minimum volume and concentration, ensure that 1) the iodine removal efficiency of the spray water is maintained because of the increase in pH value, and 2) corrosion effects on components within containment are minimized. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics. These assumptions are consistent with the iodine removal efficiency assumed in the accident analyses.

3/4.6.2.3 CONTAINMENT COOLING SYSTEM

The OPERABILITY of the containment cooling system ensures that adequate heat removal capacity is available when operated in conjunction with the containment spray systems during post-LOCA conditions.

The surveillance requirements for the service water accumulator vessels ensure each tank contains sufficient water and nitrogen to maintain water filled, subcooled fluid conditions in three containment fan coil unit (CFCU) cooling loops in response to a loss of offsite power, without injecting nitrogen covergas into the containment fan coil unit loops assuming the most limiting single failure. The surveillance requirement for the discharge valve response time test ensures that on a loss of offsite power, each discharge valve actuates to the open position in accordance with the design to allow sufficient tank discharge into CFCU piping to maintain water filled, subcooled fluid conditions in three CFCU cooling loops, assuming the most limiting single failure.

3/4.6.3 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The opening of locked or sealed closed containment isolation valves (penetration flow paths)on an intermittent basis under administrative control includes the following considerations: (1) stationing a dedicated individual, who is in constant communication with the control room, at the valve controls, (2) instructing this individual to close these valves in an accident situation, and (3) assuring that environmental conditions will not preclude access to close the valves and that this action will prevent the release of radioactivity outside the containment.

The main steam isolation valves (MSIVs) fulfill their containment isolation function as remote-manual containment isolation valves. The automatic closure of the MSIVs is not required for containment isolation due to having a closed system inside containment. The remote-manual containment isolation function of the MSIVs can be accomplished through either the use of the hydraulic operator or when the MSIV has been tested in accordance with surveillance requirement 4.7.1.5 the steam assist function can be credited.

Surveillance Requirement (SR) 4.6.3.1.3 only applies to the MS7 (Main Steam Drain) valves and the MS18 (Main Steam Bypass) valves. The MS167 (Main Steam Isolation) valves are tested for main steam isolation purposes by SR 4.7.1.5. For containment isolation purposes, the MS167s are tested as remote/manual valves pursuant to Specification 4.0.5.

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions. Either recombiner unit is capable of controlling the expected hydrogen generation associated with 1) zirconium-water reactions, 2) radiolytic decomposition of water and 3) corrosion of metals within containment.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% of its design pressure of 1085 psig during the most severe anticipated system operational transient. The MSSVs also provide protection against overpressurization of the Reactor Coolant Pressure Boundary by providing a heat sink for the removal of energy from the Reactor Coolant System if the preferred heat sink is not available. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is 16.66×10^6 lbs/hr which is 110.3 percent of the maximum calculated steam flow of 15.10×10^6 lbs/hr at 100% RATED THERMAL POWER. A minimum of 2 OPERABLE safety valves per OPERABLE steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-2.

STARTUP and/or POWER OPERATION is allowable with one or two inoperable safety valves within the limitations of the ACTION requirements on the basis of the reduction in secondary steam flow associated with the required reduction of RATED THERMAL POWER. The acceptable power level (in percent RATED THERMAL POWER) for operation with inoperable safety valves was determined by performing explicit transient analysis.

The events that challenge the relief capacity of the safety valves are those resulting in decreased heat removal capability. In this category of events, a loss of external electrical load and/or turbine trip is the limiting anticipated operational occurrence. A series of cases was analyzed for this transient covering up to two inoperable safety valves on each steam generator. The results of these cases were used to determine a maximum thermal power level from which the event could be initiated without exceeding the primary and secondary side design pressure limits. Thus, the maximum allowed power level as a function of the number of inoperable MSSVs on any steam generator is presented in Table 3.7-1. Note that the power level values presented on this table are the direct inputs into the transient analysis cases and do not include any allowance for calorimetric error. Actual power level reductions must include calorimetric uncertainty and other allowances for operating margin as deemed necessary.

Specific accident analyses for RCCA Bank Withdrawal at Power scenarios demonstrate that adequate safety valve relief capacity exist with up to two inoperable safety relief valves on each steam generator. These cases demonstrate that the reactor trip on OTDT along with the relief from the available main steam safety valves is sufficient to meet secondary side pressurization limits.

For three inoperable main steam safety valves in one or more steam generators, thermal reactor power must be reduced in conjunction with a reduction in the Power Range Neutron Flux High trip setpoint to prevent overpressurization of the main steam system.

The transient analysis assumes that the MSSVs will start to open at the lift setpoint with 3% allowance for setpoint tolerance. In addition, the analysis accounts for accumulation by including a 5 psi ramp for the valve to reach its fully open position. Inoperable MSSVs are assumed to be those with the lowest lift setting. Surveillance testing as covered in Table 4.7-1 allows a ± 3% lift setpoint tolerance. However, to allow for drift during subsequent operation, the valves must be reset to within ± 1% of the lift setpoint following testing.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the auxiliary feedwater system ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of off-site power.

Verifying that each Auxiliary Feedwater (AFW) pump's developed head at the flow test point is greater than or equal to the required minimum developed head ensures that the AFW pump performance has not degraded during the cycle, and that the assumptions made in the accident analysis remain valid. Flow and differential head are normal tests of centrifugal pump performance required by Section XI of the ASME Code. Because it is undesirable to introduce cold AFW into the steam generators while operating, the test is performed on recirculation flow. This test confirms one point on the pump design curve (head vs flow curve), and is indicative of pump performance. Inservice testing confirms pump operability, trends performance and detects incipient failures by indication of pump performance.

The flow path to each steam generator is ensured by maintaining all manual maintenance valves locked open. A spool piece consisting of a length of pipe may be used as an equivalent to a locked open manual valve. The manual valves in the flow path are: 1AF1, 11AF3, 12AF3, 13AF3, 11AF10, 12AF10, 13AF10, 14AF10, 11AF20, 12AF20, 13AF20, 14AF20, 11AF22, 12AF22, 13AF22, 14AF22, 11AF86, 12AF86, 13AF86, and 14AF86.

LCO 3.0.4.b is not applicable to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

3/4.7.1.3 AUXILIARY FEED STORAGE TANK

The OPERABILITY of the auxiliary feed storage tank with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 8 hours with steam discharge to the atmosphere concurrent with total loss of off-site power. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant off-site radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the accident analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

If the closure time of the main steam isolation valve (MSIV) during technical specification surveillance testing (performed at a Steam Generator pressure between 800 psig and 1015 psig) is 5.0 seconds or less and the engineered safety feature response time (including valve closure time) for the steam line isolation (MSI) signal (Table 3.3-5) is 5.5 seconds or less, then assurance is provided that MSI occurs within 12 seconds under accident conditions, where Steam Generator pressure may be lower. This method of testing assures that for main steam line ruptures that are initiated from Modes 1-3 conditions that generate a MSI signal via automatic or manual initiation and have adequate steam line pressure to close, the main steam lines isolate within the time required by the accident analysis. Fast closure of the MSIVs is assured at a minimum steam pressure of 170 psia. However, the MSIV will still close via the steam assist function between 118 - 170 psia with slightly greater closure times. For main steam line ruptures that receive an automatic or manual signal for MSI and do not have adequate steam pressure to close the MSIVs (less than 118 psia), the event does not require MSIV closure to provide protection to satisfy design basis requirements (e.g., minimum DNBR remains above the minimum DNBR limit value and peak containment pressure remains below 47 psig).

Testing for SR 4.7.1.5 is performed prior to opening the MSIVs for power operation. During testing, only one valve is opened at a time, with the other three valves remaining closed in the safe position, ensuring isolation capability is maintained. In the event of a steam line rupture, a postulated failure of the tested valve in the open position would result in the blowdown of a single steam generator since the remaining three MSIVs are closed. Failure of a single MSIV to close is consistent with the accident analysis assumptions for a major secondary system pipe rupture (UFSAR Section 15.4.2).

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70°F and 200 psig are based on average steam generator impact values taken at 10°F and are sufficient to prevent brittle fracture.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the component cooling water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The component cooling water system (CCW) consists of two safeguards mechanical trains supplied by three pumps powered from separate vital buses. This complement of equipment assures adequate redundancy in the event of a single active component failure during the injection phase. Operability of the CCW system exists when both mechanical trains and all three CCW pumps are operable.

3/4.7.4 SERVICE WATER SYSTEM

The OPERABILITY of the service water system ensures that sufficient cooling capacity is available for continued operation of safety related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.5 FLOOD PROTECTION

The limitation on flood protection ensures that facility protective actions will be taken and operation will be terminated in the event of flood conditions. The limit of elevation 10.5' Mean Sea Level is based on the elevation above which facility flood control measures are required to provide protection to safety related equipment.

3/4.7.6 CONTROL ROOM EMERGENCY AIR CONDITIONING SYSTEM

The OPERABILITY of the control room emergency air conditioning system (CREACS) ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all credible accident conditions.

The CREACS is a shared system between Unit 1 and 2 supplying a common Control Room Envelope (CRE). During emergency operation following receipt of a Safety Injection or High Radiation actuation signal, for areas inside the CRE, one 100% capacity fan in each Unit's CREACS will operate in a pressurization mode with a constant amount of outside air supplied for continued CRE pressurization to 1/8" water gauge. One fan from each train will automatically start upon receipt of an initiation signal, with one fan in each train in standby. A failure of one fan will result in the standby fan automatically starting.

Each CREACS train has two 100% capacity fans, such that any one of the four fans is sized to provide the required flow for CRE pressurization to 1/8" water gauge positive pressure within the common CRE during an emergency.

A failure of one CREACS filtration train requires manual actions to properly reposition dampers in support of single filtration train operation.

To minimize control room radiological doses, the CREACS outside air is supplied from the non-accident unit's emergency air intake through the cross-connected supply duct (as determined by which unit received an accident signal). Outside air is mixed with recirculated air, passed through each CREACS filter bank (pre-filter, HEPA filter, and charcoal filter) and cooling coil, and distributed to the common CRE.

CREACS will be manually initiated in the recirculation mode only in the event of a fire outside the CRE, a toxic chemical release, delivery of Ammonium Hydroxide or testing.

A significant contributor to this system's OPERABILITY are the dampers which are required to actuate to their correct positions. The following dampers are associated with the respective LCO*:

a.1 Fan outlet dampers: 1(2)CAA15 and 1(2)CAA16

These dampers ensure that the flow path for CREACS is operable and are required to open upon CREACS initiation. The associated fan outlet damper will open on fan operation.

a.4 Return air isolation damper: 1(2)CAA17

When aligned for single train operation, the associated air return isolation damper will be administratively controlled in the open position.

b. Other dampers required for automatic operation in the pressurization or recirculation modes:

Control Area Air Conditioning System (CAACS) outside air intake isolation dampers: 1(2)CAA40, 1(2)CAA41, 1(2)CAA43 and 1(2)CAA45

The normally open outside air intake dampers 1(2)CAA40 and inlet plenum isolation dampers 1(2)CAA43 will be closed under emergency conditions. The normally closed outside air intake dampers 1(2)CAA41 and inlet plenum isolation dampers 1(2)CAA45 are normally closed and remain closed under emergency conditions.

Control Area Air Conditioning System (CAACS) exhaust isolation dampers: 1(2)CAA18 and 1(2)CAA19.

These dampers are normally closed and are required to remain closed to prevent inleakage from the outside environment in the event of a toxic release.

Control Room Emergency Air Conditioning System (CREACS) air intake dampers: 1(2)CAA48, 1(2)CAA49, 1(2)CAA50 and 1(2)CAA51

CREACS outside air intake dampers are maintained closed during normal and recirculation operation and are opened automatically upon initiation of CREACS pressurization. The control logic will automatically open the CREACS air intake dampers farthest from the radiation source based upon which Unit's Solid State Protection System (SSPS) or Radiation Monitoring System (RMS) signal is received.

* Operability of the CREACS requires that each of the Unit 2 dampers are also operable

CAACS and CREACS interface isolation dampers: 1(2)CAA14 and 1(2)CAA20

These two dampers are normally open and do not have associated redundant dampers. These dampers serve a boundary function by isolating the CREACS from the CAACS during emergency operation of the CREACS.

Note: Dampers 1(2)CAA5, CAACS recirculation damper will receive an accident alignment signal to ensure proper accident configuration of CAACS. This damper, however, is not required for the OPERABILITY of CREACS as defined in the LCO.

The control room envelope is considered intact and able to support operation of the CREACS when the emergency air conditioning system is capable of maintaining a 1/8" water gauge positive pressure with the control room boundary door(s) closed.

Filter testing will be in accordance with the applicable sections of ANSI N510 (1975) with the exception that laboratory testing of activated carbon will be in accordance with ASTM D3803 (1989). The acceptance criteria for the laboratory testing of the carbon adsorber is determined by applying a minimum safety factor of 2 to the charcoal filter removal efficiency credited in the design basis dose analysis as specified in Generic Letter 99-02.

TS Surveillance Requirement verifies that each fan is capable of operating for at least 15 minutes by initiating flow through the HEPA filter and charcoal adsorbers train(s) to ensure that the system is available in a standby mode.

Each CAACS normal air intake ductwork will have an additional radiation detector channel installed for a total of two detectors per intake. The two detector channels from Unit 1 and Unit 2 CAACS air intake provide input to common radiation monitor processors. Each radiation monitor processor (one for 1R1B-1/1R1B-2 and one for 2R1B-1/2R1B-2) provides a signal to initiate CREACS in the pressurization mode should high radiation be detected. A minimum of one out of two detectors in either intake will initiate the pressurization mode. With two detector channels inoperable on a Unit, operation may continue as long as CREACS is placed inservice in the pressurization or recirculation mode. Pressurization mode will be initiated after 7 days with one inoperable detector. Radiological releases during a fuel handling accident while operating in the recirculation mode could result in unacceptable radiation levels in the CRE since the automatic initiation capability has been defeated for high radiation due to isolation of the detectors. Therefore, movement of irradiated fuel assemblies or Core Alterations at either Unit will not be permitted when in the recirculation mode.

Immediate action(s), in accordance with the LCO Action Statements, means that the required action should be pursued without delay and in a controlled manner.

The OPERABILITY of this system in conjunction with control room design provisions is based on providing adequate radiation protection to permit access to and occupancy of the Salem control room for the entire duration of the postulated accident, with no person in the control room receiving radiation exposure that exceeds 5 rem TEDE. This limitation is consistent with the requirements of Regulatory Guide 1.183.

3/4.7.7 AUXILIARY BUILDING VENTILATION SYSTEM

The Auxiliary Building Ventilation System (ABVS) consists of two major subsystems. They are designed to; control Auxiliary Building temperature during normal and emergency modes of operation, to maintain slightly negative pressure in the building to prevent unmonitored leakage out of the building and, to contain Auxiliary Building airborne contamination (by maintaining slightly negative pressure) during Loss of Coolant Accidents (LOCA).

The two subsystems are:

1. A once through filtration exhaust system, designed to contain particulate and gaseous contamination and prevent it from being released from the building in accordance with 10CFR20 (no credit is taken for post-accident filtration), and

2. A once through air supply system, designed to deliver outside air into the building to maintain building temperatures and negative pressure within acceptable limits. For the purposes of satisfying the Technical Specification LCO, one supply fan must be administratively removed from service such that the fan will not auto-start on an actuation signal; however, the supply fan must be OPERABLE with the exception of this administrative control.

These systems operate during normal and emergency plant modes. Additionally, the system provides a flow path for containment purge supply and exhaust during Modes 5 and 6. Either the Containment Purge system or the Auxiliary Building Ventilation System with suction from the containment atmosphere, with associated radiation monitoring will be available whenever movement of irradiated fuel is in progress in the containment building and the equipment hatch is open. If for any reason, this ventilation requirement can not be met, movement of fuel assemblies within the containment building shall be discontinued until the flow path(s) can be reestablished or close the equipment hatch and personnel airlocks.

Appropriate filtration surveillances are contained in the UFSAR Section 9.4.2.4, Test and Inspections. Auxiliary Building exhaust air filtration system functionality is not required to meet LCO 3.7.7.1.

The ventilation exhaust consists of three 50% capacity fans that are powered from vital buses. The fans are designed for continuous operation, to control the Auxiliary Building pressure at -0.10" Water Gauge with respect to atmosphere.

The ventilation supply consists of two 100% capacity fans that are powered from vital buses, and distribute outdoor air to the general areas and corridors of the building through associated ductwork.

AUXILIARY BUILDING VENTILATION ALIGNMENT MATRIX

NORMAL VENTILATION (Normal plant operations)*

Any two of the three exhaust fans and either of the two supply fans.

* The normal alignment is two exhaust fans and one supply fan. During cooler seasons, and with the absence of the system heating coils, it may be required to limit the amount of colder outside air entering the building. In this case, it is acceptable to secure both supply fans from operation and reduce the number of operating exhaust fans to one. There is sufficient capacity with the single exhaust fan to maintain the negative pressure within the auxiliary building boundary.

EMERGENCY VENTILATION (Emergency plant operations)

At least two of the three exhaust fans and either one of the two supply fans.

Note: During a Safety Injection (SI) all three exhaust fans and one of the supply fans will start. This is acceptable and will maintain the boundary pressure while supplying the required cooling to the building. Should access/egress become difficult with the three exhaust fans running, one of the exhaust fans should be secured.

OPERABILITY of the Auxiliary Building Ventilation System ensures that air, which may contain radioactive materials leaked from ECCS equipment following a LOCA, is monitored prior to release from the plant via the plant vent. Operation of this system and the resultant effect on offsite and control room dose calculations was assumed in the accident analyses. ABVS is discussed in Updated Final Safety Analysis Report (UFSAR) Section 9.4.2.

3/4.7.8 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values.

3/4.7.9 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety related systems and then only if their failure or failure of the system on which they were installed, would have no adverse effect on any safety related system.

A list of individual snubbers required to be operable per the technical specifications with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the Station Operations Review Committee. The determination shall be based on the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.) and the recommendations of Regulatory Guide 8.8 and 8.10. The addition or deletion of any snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to systems. Therefore, the required inspection interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. The inspections are performed for each category of snubbers. The snubbers are categorized by accessibility (i.e., accessible or inaccessible during reactor operation). The next visual inspection for each category may be twice, the same, or reduced by as much as two-thirds of the previous inspection interval. This interval depends on the number of unacceptable snubbers found in proportion to the total number of snubbers in each category from the most recent inspection. Intervals may be increased up to 48 months if few unacceptable snubbers are found in these inspections. The visual inspection interval will not exceed 48 months. However, as for all surveillance activities, unless otherwise noted, allowable tolerances of 25% are applicable for snubbers. Table 4.7-3 establishes three limits for determining the next visual inspection interval corresponding to the population of each category of snubbers. For a category that differs from the representative sizes provided, the values for the next inspection interval may be found by interpolation from the limits provided in Columns A, B, and C. Where the limit for unacceptable snubbers in Columns A, B, or C is determined by interpolation and includes a fractional value, the limit may be reduced to the next lower integer. The first inspection interval determined using Table 4.7-3 shall be based upon the previous inspection interval as established by the requirements in effect before amendment (161). Any inspection whose results require a shorter inspection interval will override the previous schedule.

SNUBBERS (Continued)

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection or are similarly located or exposed to the same environmental conditions, such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested during plant shutdowns at 18-month intervals. Observed failures of these sample snubbers shall require functional testing of additional units.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance program.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc...). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

3/4.7.10 CHILLED WATER SYSTEM - AUXILIARY BUILDING SUBSYSTEM

The OPERABILITY of the chilled water system ensures that the chilled water system will continue to provide the required normal and accident heat removal capability for the control room area, relay rooms, equipment rooms, and other safety related areas. Verification of the actuation of each automatic valve on a Safeguards Initiation signal includes actuation following receipt of a Safety Injection signal.

Removal of non-essential heat loads from the chilled water system in the event one chiller is inoperable ensures the remaining heat loads are within the heat removal capacity of the two operable chillers.

Removal of non-essential heat loads from the chilled water system in the event two chillers are inoperable and aligning the CREACs to the maintenance mode ensures the remaining heat loads are within the heat removal capacity of the operable chiller.

During chiller testing, operator actions can take the place of automatic actions.

During Modes 5 and 6 and during movement of irradiated fuel assemblies, chilled water components do not have to be considered inoperable solely on the basis that the backup emergency power source, diesel generator, is inoperable. This is consistent with Technical Specification 3.8.1.2 which only requires two operable diesel generators.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. Region 1, with 300 storage positions, is designed to accommodate new fuel with a maximum enrichment of 4.25 wt% U-235. Unirradiated and irradiated fuel with initial enrichments up to 5.0 wt% U-235 can also be stored in Region 1 with some restrictions. These restrictions are stated in TS 3/4.7.12. Region 2, with 1332 storage positions, is designed to accommodate unirradiated and irradiated fuel with stricter controls as compared to Region 1. These controls are also stated in TS 3/4.7.12.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the USNRC letter of April 14, 1978, to all Power Reactor Licensees - OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications (Accession # 7910310568) allows credit for soluble boron under other abnormal or accident conditions, consistent with postulated accident scenarios. For example, the most severe accident scenario is associated with the abnormal location of a fresh fuel assembly of 5.0 wt% enrichment which could, in the absence of soluble poison, result in exceeding the design reactivity limitation (k_{eff} of 0.95). This could occur if a fresh fuel assembly of 5.0 wt% enrichment were to be inadvertently loaded into a Region 1 or Region 2 storage cell otherwise filled to capacity. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Calculations for the worst case configuration confirmed that 800 ppm soluble boron (includes an appropriate allowance for boron concentration measurement uncertainty) is adequate to compensate for a mis-located fuel assembly. Subcriticality of the MDR with no movement of assemblies is achieved without credit for soluble boron and by controlling the location of each assembly in accordance with TS 3/4.7.12. Prior to movement of an assembly, it is necessary to verify the fuel storage pool boron concentration is within limit in accordance with TS 3/4.7.11.

Most postulated abnormal conditions or accidents in the spent fuel pool do not result in an increase in the reactivity of either MDR region. For example, an event that results in an increase in spent fuel pool temperature or a decrease in water density will not result in a reactivity increase. An event that results in the spent fuel pool cooling down below normal conditions does not impact the criticality analysis since the analysis assumes a water temperature of 4°C. This assures that the reactivity will always be lower over the expected range of water temperatures.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION (continued)

However, accidents can be postulated that could increase the reactivity. This increase in reactivity is unacceptable with unborated water in the storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool prevents criticality exceeding limits in both regions. The postulated accidents are basically of three types. The first type of postulated accident is an abnormal location of a fuel assembly, the second type of postulated accident is associated with lateral rack movement, and the third type of postulated accident is a dropped fuel assembly on the top of the rack. The dropped fuel assembly and the lateral rack movement have been previously shown to have negligible reactivity effects ($<0.0001\ \delta k$). The misplacement of a fuel assembly could result in Keff exceeding the 0.95 limit. However, the negative reactivity effect of a minimum soluble boron concentration of 600 ppm compensates for the increased reactivity caused by any of the postulated accident scenarios. The accident analyses are summarized in the FSAR Section 9.1.2.

The determination of 600 ppm has included the necessary tolerances and uncertainties associated with fuel storage rack criticality analyses. To ensure that soluble boron concentration measurement uncertainty is appropriately considered, additional margin is incorporated into the limiting condition for operation. As such, increasing the minimum required boron concentration in the fuel storage pool to 800 ppm conservatively covers the expected range of boron reactivity worth along with allowances associated with boron measurements.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). The fuel storage pool boron concentration is required to be greater than or equal to 800 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential critical accident scenarios. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the fuel storage pool.

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool, until a complete spent fuel storage pool verification has been performed following the last movement of fuel assemblies in the spent fuel storage pool. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION (continued)

The Required Actions are modified indicating that LCO 3.0.3 does not apply. Storage of fuel assemblies and the boron concentration in the spent fuel storage pool are independent of reactor operation. Therefore TS 3/4 3.7.11 and TS 3/4 3.7.12 include the exception to LCO 3.0.3 to preclude an inappropriate reactor shutdown. When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Alternatively, beginning a verification of the fuel storage pool fuel locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving fuel assemblies in the spent fuel pool while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving fuel assemblies in spent fuel pool while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. Region 1, with 300 storage positions, is designed to accommodate new fuel with a maximum enrichment of 4.25 wt% U-235. Unirradiated and irradiated fuel with initial enrichments up to 5.0 wt% U-235 can also be stored in Region 1 with some restrictions. These restrictions are stated in TS 3/4.7.12. Region 2, with 1332 storage positions, is designed to accommodate unirradiated and irradiated fuel with stricter controls as compared to Region 1. These controls are also stated in TS 3/4.7.12.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the USNRC letter of April 14, 1978, to all Power Reactor Licensees - OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications (Accession # 7910310568) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenario is associated with the abnormal location of a fresh fuel assembly of 5.0 wt% enrichment which could, in the absence of soluble poison, result in exceeding the design reactivity limitation (k_{eff} of 0.95). This could occur if a fresh fuel assembly of 5.0 wt% enrichment were to be inadvertently loaded into a Region 1 or Region 2 storage cell otherwise filled to capacity, for any of the configurations. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Calculations for the worst case configuration confirmed that 800 ppm soluble boron (includes an appropriate allowance for boron concentration measurement uncertainty)is adequate to compensate for a mis-located fuel assembly. Safe operation of the MDR with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with TS 3/4.7.12. Prior to movement of an assembly into a fuel assembly storage location in Region 1 or Region 2, it is necessary to perform SR 4.7.11 and either SR 4.7.12.1 or SR 4.7.12.2. In summary, before moving an assembly into the storage racks it is necessary to:

- validate that its final location meets the criticality requirements;
- and since there is a potential to misload the assembly, we need to ensure that the Fuel Storage Pool boron concentration is greater than the minimum required to preclude exceeding criticality limits prior to moving.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL (CONTINUED)

The restrictions on the placement of fuel assemblies within the spent fuel pool in accordance with TS 3/4.7.12, in the accompanying LCO, ensures the k_{eff} of the spent fuel storage pool will always remain < 0.95, assuming the pool to be flooded with unborated water.

This LCO applies whenever any fuel assembly is stored in Region 1 or Region 2 of the fuel storage pool.

The Required Actions are modified indicating that LCO 3.0.3 does not apply. Storage of fuel assemblies and the boron concentration in the spent fuel storage pool are independent of reactor operation. Therefore TS 3/4.3.7.11 and TS 3/4.3.7.12 include the exception to LCO 3.0.3 to preclude an inappropriate reactor shutdown. When the configuration of fuel assemblies stored in Region 1 or Region 2 of the spent fuel storage pool is not in accordance with TS 3/4.7.12, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with TS 3/4.7.12. If unable to move fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

The SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with TS 3/4.7.12 in the accompanying LCO.

3/4.8.1 and 3/4.8.2 A.C. SOURCES AND ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility, and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix "A" to 10 CFR Part 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the accident analyses and are based upon maintaining at least two independent sets of onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of one onsite A.C. source.

When a system or component is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may still be considered OPERABLE, provided the appropriate Actions of 3.8.1.1.a.2, b.2 or d.2 are satisfied.

Action 3.8.1.1.a.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required systems. Failure of a single offsite circuit will generally not, by itself, cause any equipment to lose normal AC power. Action 3.8.1.1.b.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. Action 3.8.1.1.d.2, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions.

These systems are powered from the independent AC electrical power train. However, redundant required systems or components credited by this specification are not necessarily powered from AC electrical sources. For example, the single train turbine-driven auxiliary feedwater pump is redundant to the two motor-driven pumps. Redundant required system or component failures consist of inoperable equipment associated with a train, redundant to the train that has an inoperable DG or offsite power.

LCO 3.0.4.b is not applicable to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The completion time for these actions is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This completion time also allows for an exception to the normal "time zero" for beginning the allowed outage time clock, starting only on discovery that both:

a. One train has no offsite power supplying its loads, one DG is inoperable or two required offsite circuits are inoperable; <u>and</u>

b. A required system or component on the other train is inoperable.

If at any time during these conditions a redundant required system or component subsequently becomes inoperable, this completion time begins to be tracked. Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System, or one required DG inoperable, coincident with one or more inoperable required support or supported systems or components that are associated with the other train that has power, results in starting the completion times for the Action. The specified time is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE AC supplies (one offsite circuit and three DGs for Condition (a), two offsite circuits and two DGs for Condition (b), or three DGs for Condition (d)) are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required system or component's function may have been lost; however, function has not been lost. The completion time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required system or component. Additionally, the completion time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The completion time for Condition d (loss of both offsite circuits) is reduced to 12 hours from that allowed for one train without offsite power (Action 3.8.1.1.a.2). The rationale is that Regulatory Guide 1.93 allows a completion time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required system or component failure exists, this assumption is not the case, and a shorter completion time of 12 hours is appropriate.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that 1) the facility can be maintained in the shutdown or refueling condition for extended time periods and 2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The Applicability of specifications 3.8.2.2, 3.8.2.4, and 3.8.2.6 includes the movement of irradiated fuel assemblies. This will insure adequate electrical power is available for proper operation of the fuel handling building ventilation system during movement of irradiated fuel in the spent fuel pool.

An offsite circuit would be considered inoperable if it were not available to one required train. Although two trains are required by LCOs 3.8.2.2 and 3.8.2.4, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and irradiated fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's actions.

With the offsite circuit or diesel generator not available to all required trains, the option exists to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With both required diesel generators inoperable, the minimum required diversity of AC power sources is not available. Therefore, it is required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required shutdown margin or boron concentration. Suspending positive reactivity additions that could result in failure to meet the minimum shutdown margin or boron concentration limit is required to assure continued safe operation.

The Surveillance Requirements for demonstrating the OPERABILITY of the diesel generators are based upon the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977. Regulatory Guide 1.108 criteria for determining and reporting valid tests and failures, and accelerated diesel generator testing, have been superseded by implementation of the Maintenance Rule for the diesel generators per 10CFR50.65. In addition to the Surveillance Requirements of 4.8.1.1.2, diesel preventative maintenance is performed in accordance with procedures based on manufacturer's recommendations with consideration given to operating experience.

The minimum voltage and frequency stated in the Surveillance Requirements (SR) are those necessary to ensure the Emergency Diesel Generator (EDG) can accept Design Basis Accident (DBA) loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential in establishing EDG OPERATILITY, but a time constraint is not imposed. The lack of a time constraint is based on the fact that a typical EDG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. In lieu of a time constraint in the SR, controls will be provided to monitor and trend the actual time to reach stable operation within the band as a means of ensuring there is no voltage regulator or governor degradation that could cause an EDG to become inoperable.

"Standby condition" for the purpose of defining the condition of the engine immediately prior to starting for surveillance requirements requires that the lube oil temperature be between 100 °F and 170 °F. The minimum lube oil temperature for an OPERABLE diesel is 100 °F.

The thirteen second time requirement for the Emergency Diesel Generator to reach rated voltage and frequency was originally based on a Westinghouse assumption of fifteen seconds that included the delay time between the occurrence of the incident and the application of electrical power to the first sequenced safeguards pump (BURL-3011, dated November 13, 1974) and included an instrument response time of two seconds (BURL-1531, dated July 27, 1970). The times specified in UFSAR Section 15.4 bound the thirteen seconds specified in the TS.

The narrower band for frequency specified for testing performed in steady state isochronous operation will ensure the EDG will not be run in an overloaded condition (steady state) during accident conditions. Steady state is assumed to be achieved after one minute of operation in the isochronous mode with all required loads sequenced on the bus.

The narrower band for steady state voltage is specified for operation when the EDG is not synchronized to the grid to ensure the voltage regulator will protect driven equipment from over-voltages during accident conditions. Procedural controls will ensure that equipment voltages are maintained within acceptable limits during testing when paralleled to the grid.

The wider band for frequency is appropriate for testing done with the governor in the droop mode. Likewise the wider band for voltage is appropriate when paralleled to the grid.

All voltages and frequencies specified in SR 4.8.1.1.2 are representative of the analytical values and do not account for postulated instrument inaccuracy. Instrument inaccuracies for EDG voltage and frequency are administratively controlled.

Preventive maintenance includes those activities (including pro-test inspections, measurements, adjustments and preparations) performed to maintain an otherwise OPERABLE EDG in an OPERABLE status. Corrective maintenance includes those activities required to correct a condition that would cause the EDG to be inoperable.

Surveillance requirement 4.8.1.2 is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of the surveillance requirement, and to preclude de-energizing a required ESF bus or disconnecting a required offsite circuit during performance of surveillance requirements. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these surveillance requirements must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE. During Startup, prior to entering Mode 4, the surveillance requirements are required to be completed if the surveillance frequency has been exceeded or will be exceeded prior to the next scheduled shutdown.

3/4.8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Containment electrical penetrations and penetration conductors are protected by either deenergizing circuits not required during reactor operation or by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers during periodic surveillance.

The surveillance frequency applicable to molded case circuit breakers and lower voltage circuit breakers provides assurance of breaker reliability by testing at least one representative sample of each manufacturer's brand of molded case and lower voltage circuit breakers. Each manufacturer's molded case circuit breakers and lower voltage circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of molded case or lower voltage circuit breakers, it is necessary to further divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

Containment penetration conductor overcurrent protective device information is provided in the UFSAR.

3/4.9.1 BORON CONCENTRATION

The limit on the boron concentration of the Reactor Coolant System (RCS), the refueling cavity, the fuel storage pool and the refueling canal during refueling ensures that the reactor remains subcritical during Mode 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the Core Operating Limits Report (COLR). Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of Keff $\leq$ 0.95 during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

General Design Criterion 26 of 10CFR 50, Appendix A requires that two independent reactivity control systems of different design principles be provided. One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps. The fuel storage pool is also adjusted to the refueling boron concentration specified in the COLR.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see TS 3/4.9.8, "Residual Heat Removal (RHR) and Coolant Circulation - All Water levels," and "Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance. The required boron concentration and the plant refueling procedures that verify the correct fuel-loading plan (including full core mapping) ensure that the Keff of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% Δk/k margin of safety is established during refueling. During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result the soluble boron concentration is relatively the same in each of these volumes.

The RCS boron concentration satisfies Criterion 2 10CFR50.36(c)(2)(ii).

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, the fuel storage pool and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core Keff ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a Keff ≤ 0.95. A note to this LCO modifies the Applicability. The note states that the limits on boron concentration are only applicable to the refueling canal, the fuel storage pool and the refueling cavity when those volumes are connected to the Reactor Coolant System. When the refueling canal, the fuel storage pool and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists. Above MODE 6, LCOs 3.1.1.1 and 3.1.1.2 ensure that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, the fuel storage pool or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately. Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g. temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately. In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions. Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

The Surveillance Requirement (SR) ensures that the coolant boron concentration in the RCS, and connected portions of the refueling canal, the fuel storage pool and the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to reconnecting portions of the refueling canal, the fuel storage pool or the refueling cavity to the RCS, this SR must be met per SR 4.0.4. If any dilution activity has occurred while the cavity or canal was disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS. A minimum frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The frequency is based on operating experience, which has shown 72 hours to be adequate.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of the source range neutron flux monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 DECAY TIME

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor pressure vessel ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. The 100-hour decay time is consistent with the assumptions used in the fuel handling accident analyses and the resulting dose calculations using the Alternative Source Term described in Reg. Guide 1.183.

The minimum requirement for reactor subcriticality also ensures that the decay time is consistent with that assumed in the Spent Fuel Pool cooling analysis. Delaware River water average temperature between October 15th and May 15th is determined from historical data taken over 30 years. The use of 30 years of data to select maximum temperature is consistent with Reg. Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants".

A core offload has the potential to occur during both applicability time frames. In order not to exceed the analyzed Spent Fuel Pool cooling capability to maintain the water temperature below 180°F, two decay time limits are provided. In addition, PSEG has developed and implemented a Spent Fuel Pool Integrated Decay Heat Management Program as part of the Salem Outage Risk Assessment. This program requires a pre-outage assessment of the Spent Fuel Pool heat loads and heatup rates to assure available Spent Fuel Pool cooling capability prior to offloading fuel.

3/4.9.4 CONTAINMENT BUILDING PENETRATIONS

During movement of irradiated fuel assemblies within containment the requirements for containment building penetration closure capability and OPERABILITY ensure that a release of fission product radioactivity within containment will not exceed the guidelines and dose calculations described in Reg. Guide 1.183, Alternative Radiological Source Term for Evaluating Design Basis Accidents at Nuclear Power Reactors. In MODE 6, the potential for containment pressurization as a result of an accident is not likely. Therefore, the requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements during movement of irradiated fuel assemblies within containment are referred to as "containment closure" rather than containment OPERABILITY. For the containment to be OPERABLE, CONTAINMENT INTEGRITY must be maintained. Containment closure means that all potential containment atmosphere release paths are closed or capable of being closed. Closure restrictions include the administrative controls to allow the opening of both airlock doors and the equipment hatch during fuel movement provided that: 1) the equipment inside door or an equivalent closure device installed is capable of being closed with four bolts within 1 hour by a designated personnel; 2) the airlock door is capable of being closed within 1 hour by a designated personnel, 3) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 4) the plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange.

Administrative requirements are established for the responsibilities and appropriate actions of the designated personnel in the event of a Fuel Handling Accident inside containment. These requirements include the responsibility to be able to communicate with the control room, to ensure that the equipment hatch is capable of being closed, and to close the equipment hatch and personnel airlocks within 1 hour in the event of a fuel handling accident inside containment. These administrative controls ensure containment closure will be established in accordance with and not to exceed the dose calculations performed using guidelines of Regulatory Guide 1.183.

The containment serves to limit the fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10CFR100 and Reg. Guide 1.183, Alternative Source Term, as applicable. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The Containment Equipment Hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into or out of containment. During movement of irradiated fuel assemblies within containment, the Containment Equipment Hatch inside door can be open provided that: 1) it is capable of being closed with four bolts within 1 hour by designated personnel, 2) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 3) The plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange. Good engineering practice dictates that the bolts required by the LCO are approximately equally spaced.

An equivalent closure device may be installed as an alternative to installing the Containment Equipment Hatch inside door with a minimum of four bolts. Such a closure device may provide penetrations for temporary services used to support maintenance activities inside containment at times when containment closure is required; and may be installed in place of the Containment Equipment Hatch inside door or outside door. Penetrations incorporated into the design of an equivalent closure device will be considered a part of the containment boundary and as such will be subject to the requirements of Technical Specification 3/4.9.4. Any equivalent closure device used to satisfy the requirements of Technical Specification 3/4.9.4.a will be designed, fabricated, installed, tested, and utilized in accordance with established procedures to ensure that the design requirements for the mitigation of a fuel handling accident during refueling operations are met. In case that this equivalent closure device is installed in lieu of the equipment hatch inside door, the same restrictions and administrative controls apply to ensure closure will take place within 1 hour following a FHA inside containment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during operation in MODES 1, 2, 3, and 4 as specified in LCO 3.6.1.3, "Containment Air Locks". Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown, when containment closure is not required and frequent containment entry is necessary, the air lock interlock mechanism may be disabled. This allows both doors of an airlock to remain open for extended periods.

During movement of irradiated fuel assemblies within containment, containment closure may be required; therefore, the door interlock mechanism may remain disabled, and both doors of each containment airlock may be open if: 1) At least one door of each airlock is capable of being closed within 1 hour by a dedicated individual, 2) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 3) the plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange.

In the postulated Fuel Handling Accident, the revised dose calculations, performed using 10 CFR 50.67 and Regulatory Guide 1.183, Alternative Source Term, do not take credit for automatic containment purge isolation thus allowing for continuous monitoring of containment activity until containment closure is achieved. If required, containment purge isolation can be initiated manually from the control room.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods may include the use of a material that can provide a temporary atmospheric pressure, ventilation barrier. Any equivalent method used to satisfy the requirements of Technical Specification 3/4.9.4.c.1 will be designed, fabricated, installed, tested, and utilized in accordance with established procedures to ensure that the design requirements for the mitigation of a fuel handling accident during refueling operations are met.

The surveillance requirement 4.9.4.2 demonstrates that the necessary hardware, tools, and equipment are available to close the equipment hatch. The surveillance is performed prior to movement of irradiated fuel assemblies within the containment. This surveillance is only required to be met when the equipment hatch is to be open during fuel movement.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity conditions during CORE ALTERATIONS.

3/4.9.6 MANIPULATOR CRANE

The OPERABILITY requirements for the manipulator cranes ensure that: 1) manipulator cranes will be used for movement of control rods and fuel assemblies, 2) each crane has sufficient load capacity to lift a control rod or fuel assembly, and 3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE BUILDING

The restriction on movement of loads in excess of the nominal weight of a fuel and control rod assembly and associated handling tool over other fuel assemblies in the storage pool ensures that in the event this load is dropped (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the accident analyses.

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirements that at least one residual heat removal loop be in operation ensures that (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F as required during the REFUELING MODE, and (2) sufficient coolant circulation is maintained through the reactor core to minimize the effects of a boron dilution incident and prevent boron stratification. A minimum flow rate of 1000 gpm is required. Additional flow limitations are specified in plant procedures, with the design basis documented in the Salem UFSAR. These flow limitations address the concerns related to vortexing and air entrapment in the Residual Heat Removal system, and provide operational flexibility by adjusting the flow limitations based on time after shutdown. The requirement to have two RHR loops OPERABLE when there is less than 23 feet of water above the reactor vessel flange ensures that a single failure of the operating RHR loop will not result in a complete loss of residual heat removal capability.

For support systems: Service Water (SW) and Component Cooling (CC), component redundancy is necessary to ensure no single active component failure will cause the loss of Decay Heat Removal. One piping path of SW and CC is adequate when it supports both RHR loops. The support systems needed before entering into the desired configuration (e.g., one service water loop out for maintenance in Modes 5 and 6) are controlled by procedures, and include the following:

- A requirement that the two RHR, two CC and two SW pumps, powered from two different vital buses be kept operable
- A listing of the active (air/motor operated) valves in the affected flow path to be locked open or disabled.

Note that four filled reactor coolant loops, with at least two steam generators with at least their secondary side water level greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop. This ensures that a single failure does not cause a loss of decay heat removal.

With the reactor vessel head removed and 23 feet of water above the reactor pressure vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR loop, adequate time is provided to initiate emergency procedures to cool the core.

3/4.9.9 (NOT USED)

3/4.9.10 and 3/4/9/11 WATER LEVEL - REACTOR VESSEL AND STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.12 FUEL HANDLING AREA VENTILATION SYSTEM

The operability of the Fuel Handling Area Ventilation System during movement of irradiated fuel ensures that a release of fission product radioactivity within the Fuel Handling Building will not exceed the guidelines and dose calculations described in Reg. Guide 1.183, Alternative Radiological Source Term for Evaluating Design Basis Accidents at Nuclear Power Reactors.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.1 SHUTDOWN MARGIN

This special test exception provides that a minimum amount of control rod worth is immediately available for reactivity control when tests are performed for control rod worth measurement. This special test exception is required to permit the periodic verification of the actual versus predicted core reactivity condition occurring as a result of fuel burnup or fuel cycling operations.

3/4.10.2 GROUP HEIGHT, INSERTION, AND POWER DISTRIBUTION LIMITS

This special test exception permits individual control rods to be positioned outside of their normal group heights and insertion limits during the performance of such PHYSICS TESTS as those required to 1) measure control rod worth and 2) determine the reactor stability index and damping factor under xenon oscillation conditions.

3/4.10.3 PHYSICS TESTS

This special test exception permits PHYSICS TESTS to be performed at less than or equal to 5% of RATED THERMAL POWER and is required to verify the fundamental nuclear characteristics of the reactor core and related instrumentation.

3/4.10.4 NO FLOW TESTS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.11.1 LIQUID EFFLUENTS

3/4.11.1.1 Deleted

3/4.11.1.2 Deleted

3/4.11.1.3 Deleted

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 Deleted

3/4.11.2.2 Deleted

3/4.11.2.3 Deleted

3/4.11.2.4 Deleted

3/4.11.2.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the waste gas holdup system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of oxygen below the specified values provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

This specification is not applicable to portions of the Waste Gas System Removed from service for maintenance, provided that the portions removed for maintenance are isolated from sources of hydrogen and purged of hydrogen to less than 4% by volume.

3/4.11.3 Deleted

3/4.11.4 Deleted

3/4.12 Deleted

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5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be shown in Figure 5.1.1

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1-2.

UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC, shall be as shown in Figure 5.1-3.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The reactor containment building is a steel lined, reinforced concrete building of cylindrical shape, with a dome roof and having the following design features:

a. Nominal inside diameter = 140 feet.

b. Nominal inside height = 210 feet.

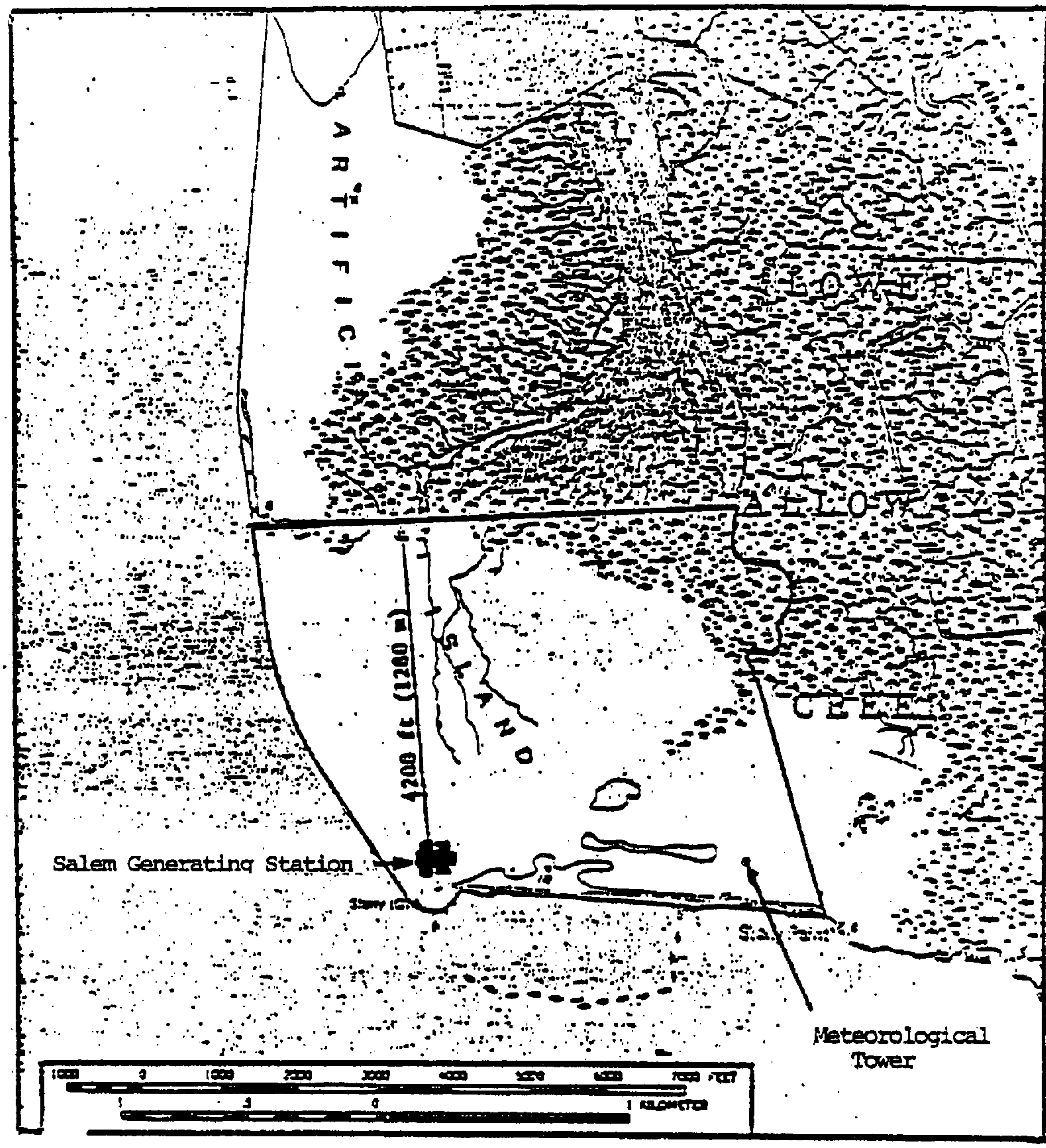
c. Minimum thickness of concrete walls = 4.5 feet.

d. Minimum thickness of concrete roof = 3.5 feet.

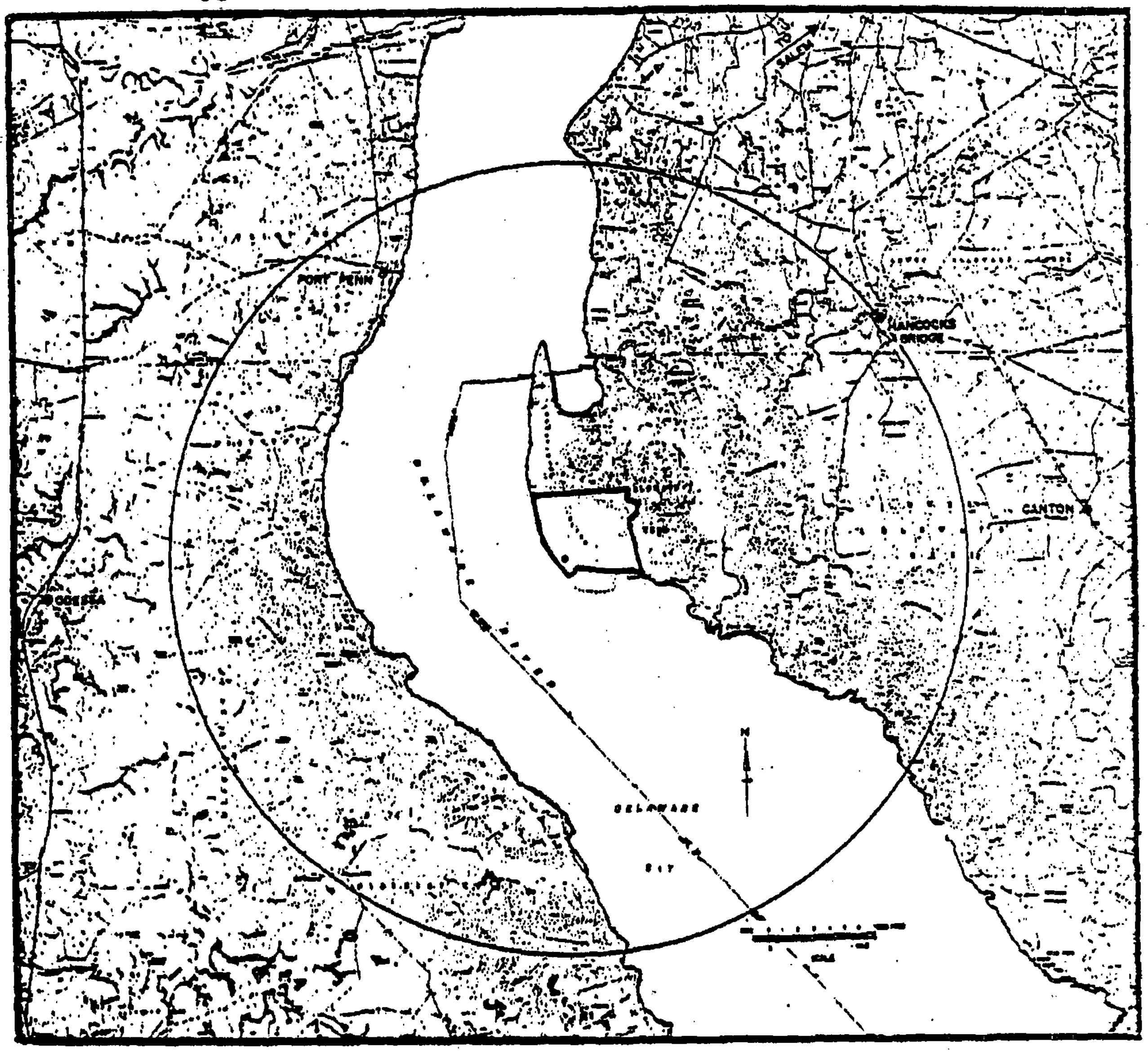
e. Minimum thickness of concrete floor mat = 16 feet.

f. Nominal thickness of steel liner = 1/4 to 1/2 inch.

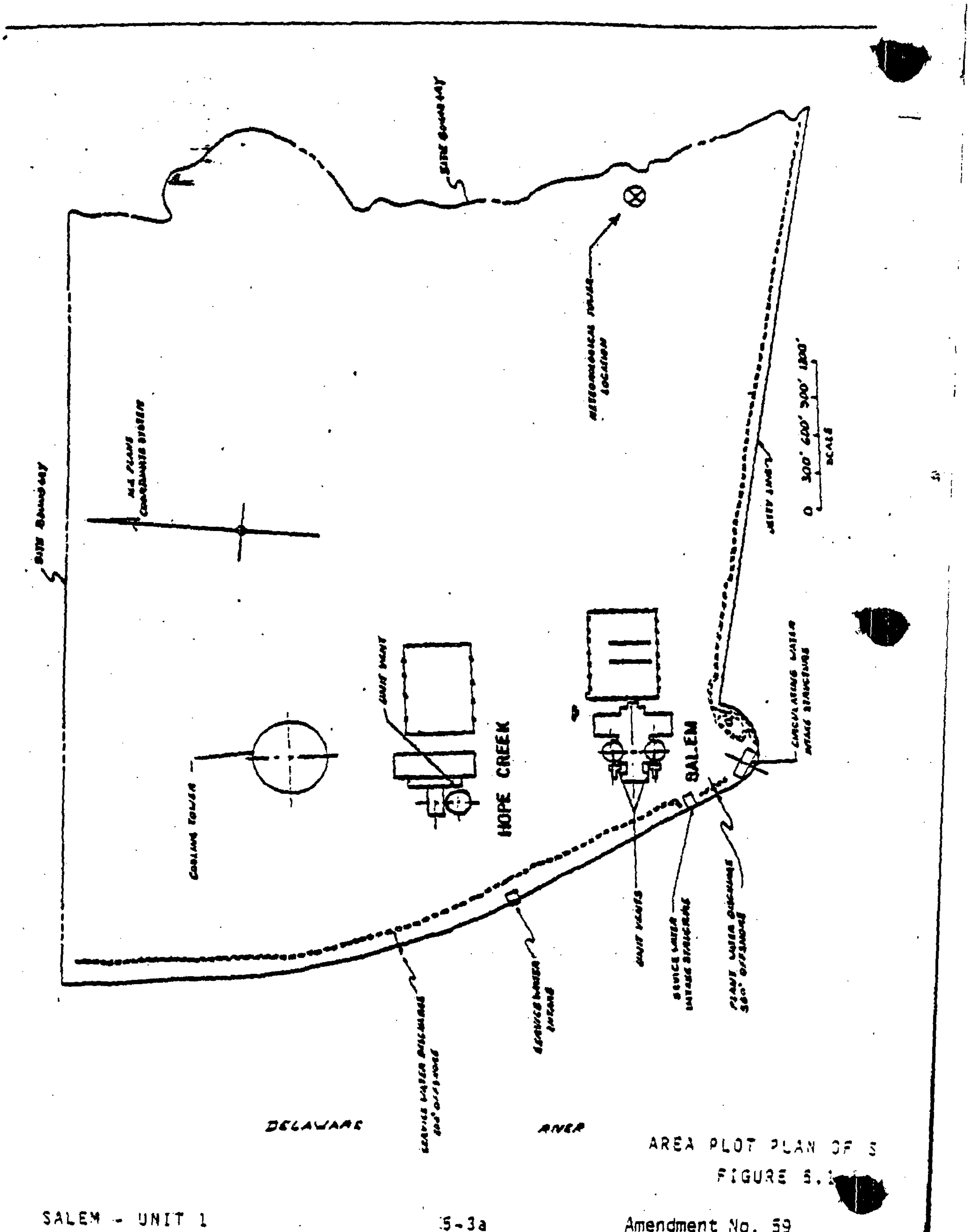
g. Net free volume = 2.62×10^6 cubic feet.



EXCLUSION AREA
FIGURE 5.1-1



LOW POPULATION ZONE
FIGURE 5.1-2



AREA PLOT PLAN OF S

FIGURE 5.1

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The reactor containment is designed and shall be maintained for a maximum internal pressure of 47 psig. Containment air temperatures up to 351.3°F are acceptable providing the containment pressure is in accordance with that described in the UFSAR.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of zircaloy or ZIRLO clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with NRC-approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

CONTROL ROD ASSEMBLIES

5.3.2 The reactor core shall contain 53 full length and no part length control rod assemblies. The full length control rod assemblies shall contain a nominal 142 inches of absorber material. The nominal values of absorber material shall be 80 percent silver, 15 percent indium and 5 percent cadmium. All control rods shall be clad with stainless steel tubing.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 4.1 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 680°F.

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1.1 The new fuel storage racks are designed and shall be maintained with:

a. A maximum K_{eff} equivalent of 0.95 with the storage racks flooded with unborated water.

b. A nominal 21.0 inch center-to-center distance between fuel assemblies.

c. Unirradiated fuel assemblies with enrichments less than or equal to 4.25 weight percent (w/o) U-235 with no requirements for Integral Fuel Burnable Absorber (IFBA) pins.

d. Unirradiated fuel assemblies with enrichments (E) greater than 4.25 w/o U-235 and less than or equal to 5.0 w/o U-235 which contain a minimum number of Integral Fuel Burnable Absorber (IFBA) pins. This minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5X), determined by the equation below:

$$N = 42.67 (E - 4.25)$$

5.6.1.2 The spent fuel storage racks are designed and shall be maintained with:

a. A maximum K_{eff} equivalent of 0.95 with the storage racks filled with unborated water.

b. A nominal 10.5 inch center-to-center distance between fuel assemblies stored in Region 1 (flux trap type) racks.

c. A nominal 9.05 inch center-to-center distance between fuel assemblies stored in Region 2 (non-flux trap) racks.

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DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 124'8".

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1632 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.7.1 The components identified in Table 5.7-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7-1.

TABLE 5.7-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at $\leq$ 100°F/hr and 200 cooldown cycles at $\leq$ 100°F/hr (pressurizer cooldown at $\leq$ 200°F/hr).	Heatup cycle - T_{avg} from $\leq$ 200°F to $\geq$ 542°F. Cooldown cycle - T_{avg} from $\geq$ 542°F to $\leq$ 200°F.
	80 loss of load cycles.	Without immediate turbine or reactor trip.
	40 cycles of loss of offsite A.C. electrical power.	Loss of offsite A.C. electrical power source supplying the onsite Class 1E distribution system.
	80 cycles of loss of flow in one reactor coolant loop.	Loss of only one reactor coolant pump.
	400 reactor trip cycles.	100% to 0% of RATED THERMAL POWER.
	200 large step decreases in load.	50% of RATED THERMAL POWER step load decrease with steam dump.

TABLE 5.7-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	1 main reactor coolant pipe break.	Break in a reactor coolant pipe $\geq$ 13.5 inches equivalent diameter.
	Operating Basis Earthquake	50 cycles
	Design Basis Earthquake	10 cycles; 0.20g horizontal, 0.136g vertical.
	50 leak tests.	Pressurized to $\geq$ 2485 psig.
	5 hydrostatic pressure tests	Pressurized to $\geq$ 3107 psig.
Secondary System	1 steam line break	Break in a steam line > 6 inches equivalent diameter.
	5 hydrostatic pressure tests	Pressurized to $\geq$ 1356 psig.
	10 turbine roll tests	Turbine roll on pump heat resulting in plant cooldown > 100°F/hr.

6.1 RESPONSIBILITY

6.1.1 The plant manager shall be responsible for overall facility operation and shall delegate, in writing, the succession to this responsibility during his absence.

6.1.2 The Senior Nuclear Shift Supervisor or, during his absence from the control room, a designated individual, shall be responsible for the control room command function. A management directive to this effect, signed by the senior corporate nuclear officer, shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

6.2.1 ONSITE AND OFFSITE ORGANIZATIONS

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be established and defined from the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Salem Updated Final Safety Analysis Report and updated in accordance with 10 CFR 50.71(e).

b. The plant manager shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. The senior corporate nuclear officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

6.2.2 FACILITY STAFF

The facility organization shall be subject to the following:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1;

b. At least one licensed Reactor Operator shall be in the control room when fuel is in the reactor. In addition, at least one licensed Senior Reactor Operator shall be in the Control Room area at all times.

c. All CORE ALTERATIONS shall be observed and directly supervised by a licensed Senior Reactor Operator who has no other concurrent responsibilities during this operation.

d. Administrative controls shall be developed and implemented to limit the working hours of personnel who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel, et al.). The controls shall include guidelines on working hours that ensure that adequate shift coverage is maintained without heavy use of overtime for individuals.

Any deviation from the working hour guidelines shall be authorized in advance by the plant manager or his designee, in accordance with approved administrative procedures and with documentation of the basis for granting the deviation.

Controls shall be included in the procedure such that overtime shall be reviewed monthly by the plant manager or his designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines shall not be authorized.

Figure 6.2-1 CORPORATE HEADQUARTERS AND OFF-SITE ORGANIZATION FOR MANAGEMENT AND TECHNICAL SUPPORT

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FIGURE 6.2 - 2 FACILITY ORGANIZATION

(Deleted)

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION

SALEM UNIT 1

WITH UNIT 2 IN MODES 5 OR 6 OR DE-FUELED

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODES 1, 2, 3 & 4	MODES 5 & 6
SNSS	1[a]	1[a]
SRO	1[b]	none
STA	1[b]	none
NCO	2	1
EO/UO	3	2[c]
Maintenance Electrician	1	none
Rad. Pro. Technician	1[a]	1[a,e]

WITH UNIT 2 IN MODES 1, 2, 3 OR 4

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODES 1, 2, 3 & 4	MODES 5 & 6
SNSS	1[a]	1[a]
SRO	1[b]	none
STA	1[b]	none
NCO	2	1
EO/UO	3[d]	1
Maintenance Electrician	1[a]	none
Rad. Pro. Technician	1[a]	1[a]

a/ Individual may fill the same position on Unit 2.

b/ Individual who fulfills the STA requirement may fill the same position on Unit 2. The STA, if a licensed SRO, may concurrently fill the SRO position on one unit; the other unit also requires a qualified SRO on shift.

c/ One of the two required individuals may fill the position on Unit 2, such that there are a total of three EO/UO's for both units.

d/ One of the three required individuals may fill the same position of Unit 2, such that there are a total of five EO/UO's for both units.

e/ Not needed if both reactors are de-fueled.

TABLE 6.2-1 (Continued)

SNSS - Senior Nuclear Shift Supervisor with a Senior Reactor Operator License on both units.

SRO - Individual with a Senior Reactor Operator License on both units (normally, a Nuclear Shift Supervisor).

NCO - Nuclear Control Operator with a Reactor Operator License on both units.

STA - Shift Technical Advisor (if licensed as SRO, may be assigned duties as a Nuclear Shift Supervisor).

EO/UO - Equipment Operator or Utility Operator.

Except for the Senior Nuclear Shift Supervisor, the Shift Crew Composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate the unexpected absence of on-duty shift crew members provided that immediate action is taken to restore the Shift Crew Composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewperson's being late or absent.

During any absence of the Senior Nuclear Shift Supervisor from the Control Room area while the unit is in any MODE, an individual with a valid SRO License shall be designated to assume the Control Room command function.

6.2.3 SHIFT TECHNICAL ADVISOR

6.2.3.1 The Shift Technical Advisor shall serve in an advisory capacity to the Senior Nuclear Shift Supervisor on matters pertaining to the engineering aspects assuring safe operation of the unit.

6.2.3.2 The Shift Technical Advisor shall have a Bachelor's Degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant for transients and accidents.

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the individual designated as the Radiation Protection Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, the individual designated as the Operations Manager who shall meet or exceed the minimum qualifications of ANSI N18.1-1971 except as modified by Specification 6.3.3, and the licensed operators who shall comply with the requirements of 10CFR55.

6.3.2 The Operations Manager or Assistant Operations Manager shall hold an SRO license. The Senior Nuclear Shift Supervisors and Nuclear Shift Supervisors shall each hold a senior reactor operator license. The Nuclear Control Operators shall hold reactor operator licenses.

6.3.3 The Operations Manager shall meet one of the following:

1) Hold an SRO license, or

2) Have held an SRO license for a similar unit (PWR), or

3) Have been certified at an appropriate simulator for equivalent senior operator knowledge.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the facility staff shall:

1) be coordinated by each functional level manager (Department Head) at the facility and maintained under the direction of the Director - Nuclear Training

2) meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 for all affected positions except licensed operators and

3) comply with the requirements of 10CFR55 for licensed operators.

6.5 <u>REVIEW AND AUDIT</u> (THIS SECTION DELETED)

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6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Section 50.73 to 10CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the Station Operations Review Committee (SORC) and the resultant Licensee Event Report submitted to the Nuclear Review Board and the senior corporate nuclear officer.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The unit shall be placed in at least HOT STANDBY within one hour.

b. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within one hour. The senior corporate nuclear officer and senior management position with responsibility for independent nuclear safety assessment activities and quality program oversight shall be notified within 24 hours.

c. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the SORC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence.

d. The Safety Limit Violation Report shall be submitted to the Commission, the senior management position with responsibility for independent nuclear safety assessment activities and quality program oversight and the senior corporate nuclear officer within 14 days of the violation.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

g. PROCESS CONTROL PROGRAM implementation.

h. OFFSITE DOSE CALCULATION MANUAL implementation.

i. Quality Assurance Program for effluent and environmental monitoring.

6.8.2 Each procedure and administrative policy of 6.8.1 above, except 6.8.1.d and 6.8.1.e, and changes thereto, shall be reviewed and approved in accordance with requirements in Updated Final Safety Analysis Report (UFSAR) section 17.2 for SORC or for Technical Review and Control, as appropriate, prior to implementation and reviewed periodically as set forth in administrative procedures. Procedures of 6.8.1.d and 6.8.1.e shall be reviewed and approved in accordance with the Facility's Security and Emergency Plans or requirements in Updated Final Safety Analysis Report (UFSAR) section 17.2 for Technical Review and Control, as appropriate, prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 On-the-spot changes to procedures of 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered.

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License on the unit affected.

c. The change is documented and receives the same level of review and approval as the original procedure within 14 days of implementation.

6.8.4 The following programs shall be maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include (recirculation spray, safety injection, chemical and volume control, gas stripper, recombiners, ...). The program shall include the following:

(i) Preventative maintenance and periodic visual inspection requirements, and

(ii) Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in areas under accident conditions. This program shall include the following:

(i) Training of personnel,

(ii) Procedures for monitoring, and

(iii) Provisions for maintenance of sampling and analyses equipment.

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

(i) Identification of a sampling schedule for the critical variables and the control points for these variables,

(ii) Identification of the procedures used to measure the values of the critical variables,

(iii) Identification of process sampling points, including monitoring at the discharge of the condensate pumps for evidence of condenser in-leakage.

(iv) Procedures for the recording and management of data,

(v) Procedures defining corrective actions for off-control-point chemistry conditions,

(vi) A procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

d. <u>Backup Method for Determining Subcooling Margin</u>

A program which will ensure the capability to accurately monitor the Reactor Coolant System Subcooling Margin. This program shall include the following:

(i) Training of personnel, and

(ii) Procedures for monitoring

e. Deleted

6.8.4.f. <u>Primary Containment Leakage Rate Testing Program</u>

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 47.0 psig.

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.6 L_a for Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a,

2) Seal leakage rate less than or equal to 0.01 L_a per hour when the gap between the door seals is pressurized to 10.0 psig.

Test frequencies and applicable extensions will be controlled by the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 will be applied to the Primary Containment Leakage Rate Testing Program.

6.8.4.g Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to the MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 CFR 20, Appendix B, Table II, Column 2,

3) Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.106 and with the methodology and parameters in the ODCM,

4) Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5) Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days.

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 92-day period would exceed a suitable fraction of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the SITE BOUNDARY conforming to the doses associated with 10 CFR Part 20, Appendix B, Table II, Column 1,

8) Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

6.8.4.h Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of the census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

6.8.4.i Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gallon per minute per SG.

3. The operational leakage performance criterion is specified in LCO 3.4.6.2, "Reactor Coolant System Operational Leakage."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following repair criteria are applicable only for Refueling Outage 18 and the subsequent operating cycle: In lieu of the 40% of the nominal wall thickness repair criteria, the portion of the tube within the tubesheet of the inspected SGs shall be plugged in accordance with the following alternate repair criteria: Tubes with flaws located below 17 inches from the top of the tubesheet may remain in service regardless of size. Tubes with flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged on detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria.

In lieu of the above, the following inspection criteria are applicable only for Refueling Outage 18 and the subsequent operating cycle: The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube beginning 17 inches below the top of the tubesheet on the tube hot leg side to 17 inches below the top of the tubesheet on the tube cold leg side.

The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-to-secondary leakage.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, with a copy to the USNRC Administrator, Region I, unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant.

6.9.1.2 The startup report shall address each of the tests identified in the FSAR and shall include a description of measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year.

* A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

6.9.1.5 Reports required on an annual basis shall include:

a. DELETED

b. DELETED

c. The results of any specific activity analyses in which the Primary coolant exceeded the limits of Specification 3.4.8. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while the limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

MONTHLY OPERATING REPORT

6.9.1.6 DELETED

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.7 The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The report shall include summaries, interpretations, and analysis of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR 50.

ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.8 The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous 12 months of operation shall be submitted before May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objective outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR 50.

* A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

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6.9.1.9 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Moderator Temperature Coefficient Beginning of Life (BOL) and End of Life (EOL) limits and 300 ppm surveillance limit for Specification 3/4.1.1.4,

2. Control Bank Insertion Limits for Specification 3/4.1.3.5,

3. Axial Flux Difference Limits and target band for Specification 3/4.2.1,

4. Heat Flux Hot Channel Factor, F_Q, its variation with core height, K(z), and Power Factor Multiplier PF_{xy}, Specification 3/4.2.2, and

5. Nuclear Enthalpy Hot Channel Factor, and Power Factor Multiplier, $PF_{\Delta H}$ for Specification 3/4.2.3.

6. Refueling boron concentration per Specification 3.9.1

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, July 1985 (W Proprietary), Methodology for Specifications listed in 6.9.1.9.a. Approved by Safety Evaluation dated May 28, 1985.

2. WCAP-8385, Power Distribution Control and Load Following Procedures - Topical Report, September 1974 (W Proprietary). Methodology for Specification 3/4.2.1 Axial Flux Difference. Approved by Safety Evaluation dated January 31, 1978.

3. WCAP-10054-P-A, Rev. 1, Westinghouse Small Break ECCS Evaluation Model Using NOTRUMP Code, August 1985 (W Proprietary), Methodology for Specification 3/4.2.2 Heat Flux Hot Channel Factor. Approved for Salem by NRC letter dated August 25, 1993.

4. WCAP-10266-P-A, Rev. 2, The 1981 Version of Westinghouse Evaluation Model Using BASH Code, Rev. 2. March 1987 (W Proprietary) Methodology for Specification 3/4.2.2 Heat Flux Hot Channel Factor. Approved by Safety Evaluation dated November 13, 1986.

5. WCAP-12472-P-A, BEACON - Core Monitoring and Operations Support System, Revision 0, (W Proprietary). Approved February 1994.

6. CENPD-397-P-A, Rev. 1, Improved Flow Measurement Accuracy Using Crossflow Ultrasonic Flow Measurement Technology, May 2000.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

6.9.1.10 STEAM GENERATOR TUBE INSPECTION REPORT

A report shall be submitted within 180 days after the initial entry into HOT SHUTDOWN following completion of an inspection performed in accordance with the Specification 6.8.4.i, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date, and

g. The results of condition monitoring, including the results of tube pulls and in-situ testing.

h. The following reporting requirements are applicable only for Refueling Outage 18 and the subsequent operating cycle:
The number of indications detected in the upper 17 inches of the tubesheet thickness along with their location, measured size, orientation, and whether the indication initiated on the primary or secondary side.

i. The following reporting requirement is applicable only for Refueling Outage 18 and the subsequent operating cycle:
The operational primary to secondary leakage rate observed in each steam generator during the cycle preceding the inspection and the calculated accident leakage rate for each steam generator from the lowermost 4 inches of tubing (the tubesheet is nominally 21.03 inches thick) for the most limiting accident. If the calculated leak rate is less than 2 times the total observed operational leakage rate, the 180 day report should describe how the calculated leak rate is determined.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, with a copy to the Administrator, USNRC Region I within the time period specified for each report.

6.9.3 Violations of the requirements of the fire protection program described in the Updated Final Safety Analysis Report which would have adversely affected the ability to achieve and maintain safe shutdown in the event of a fire shall be submitted to the U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator of the Regional Office of the NRC via the Licensee Event Report System within 30 days.

6.9.4 When a report is required by ACTION 8 or 9 of Table 3.3-11 "Accident Monitoring Instrumentation", a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring for inadequate core cooling, the cause of the inoperability, and the plans and schedule for restoring the instrument channels to OPERABLE status.

6.10 RECORD RETENTION

In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. DELETED

f. Records of changes made to Operating Procedures required by Specification 6.8.1.

g. Records of radioactive shipments.

h. Records of sealed source and fission detector leak tests and results.

i. Records of annual physical inventory of all sealed source material of record.

j. Records of reviews performed for changes made to procedures or reviews of tests and experiments, pursuant to 10CFR50.59.

6.10.2 The following records shall be retained for the duration of the Unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report, pursuant to 10CFR50.59.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of radiation exposure for all individuals entering radiation control areas.

d. Records of gaseous and liquid radioactive material released to the environs.

e. Records of transient or operational cycles for those facility components identified in Table 5.7-1.

f. Records of reactor tests and experiments.

g. Records of training and qualification for current members of the plant staff.

h. Records of in-service inspections performed pursuant to these Technical Specifications.

i. Records of Quality Assurance activities required by the QA Manual.

j. DELETED

k. Records of SORC meetings and activities of the Nuclear Review Board (and activities of its predecessor, the Offsite Safety Review (OSR) staff.)

l. Records for Environmental Qualification which are covered under the provisions of Paragraph 6.16.

m. Records of the service lives of all hydraulic and mechanical snubbers including the date at which the service life commences and associated installation and maintenance records.

n. Records of secondary water sampling and water quality.

o. Records of analyses required by the radiological environmental monitoring program which would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed.

p. Records of reviews performed for changes made to the OFFSITE DOSE CALCULATION MANUAL and the PROCESS CONTROL PROGRAM.

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

6.12.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

6.12.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

   (i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

   (ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Changes to the PCP:

1. Shall be documented and records of review performed shall be retained as required by Specification 6.10.3p. This documentation shall contain:

   a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   b) A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall become effective after review and acceptance by the SORC and the approval of the Plant Manager.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

6.14.2 Changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained as required by Specification 6.10.3p. This documentation shall contain:

   a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   b) A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.106, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

2. Shall become effective after review and acceptance by the SORC and the approval of the Plant Manager.

3. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g. month/year) the change was implemented.

6.15 MAJOR CHANGES TO RADIOACTIVE LIQUID, GASEOUS AND SOLID WASTE TREATMENT SYSTEMS

6.15.1 Licensee initiated major changes to the radioactive waste system (liquid, gaseous and solid):

1. Shall be reported to the Commission in the UFSAR for the period in which the evaluation was reviewed by (SORC). The discussion of each change shall contain:

   a. A summary of the evaluation that led to the determination that the change could be made in accordance with 10CFR50.59;

   b. Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

c. A detailed description of the equipment, components and processes involved and the interfaces with other plant systems;

d. An evaluation of the change, which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the license application and amendments thereto;

e. An evaluation of the change, which shows the expected maximum exposures to individual in the unrestricted area and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the changes are to be made;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the (SORC).

2. Shall become effective upon review and acceptance by the SORC.

6.16 ENVIRONMENTAL QUALIFICATION

6.16.1 All safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines); or, NUREG-0588 "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979. Copies of these documents are attached to Order for Modification of License No. DPR-70 dated October 24, 1980.

6.16.2 Complete and auditable records shall be available and maintained at a central location which describe the environmental qualification method used for all safety related electrical equipment in sufficient detail to document the degree of compliance with the DOR Guidelines or NUREG-0588. Such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.17 TECHNICAL SPECIFICATION (TS) BASES CONTROL PROGRAM

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. PSEG may make changes to the Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the License, or

   2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. Proposed changes to the Bases that require either condition of Specification 6.17.b above shall be reviewed and approved by the NRC prior to implementation.

d. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

e. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

APPENDIX B

TO

FACILITY OPERATING LICENSE NO. DPR-70

SALEM GENERATING STATION UNIT 1

DOCKET NO. 50-272

AND

FACILITY OPERATING LICENSE NO. DPR-75

SALEM GENERATING STATION UNIT 2

DOCKET NO. 50-311

PSEG NUCLEAR LLC

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

SALEM GENERATING STATION
UNIT NOS. 1 AND 2

ENVIRONMENTAL PROTECTION PLAN
(NONRADIOLOGICAL)

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1.0 Objectives of the Environmental Protection Plan

The Environmental Protection Plan (EPP) is to provide for protection of nonradiological environmental values during operation of the nuclear facility. The principal objectives of the EPP are as follows:

(1) Verify that the facility is operated in an environmentally acceptable manner, as established by the Final Environmental Statement - Operating Licensing Stage (FES-OL) and other NRC environmental impact assessments.

(2) Coordinate NRC requirements and maintain consistency with other Federal, State and local requirements for environmental protection.

(3) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects.

Environmental concerns identified in the FES-OL which relate to water quality matters are regulated by way of the licensee's NJPDES permit.

2.0 Environmental Protection Issues

In the FES, dated April 1973, the staff considered the environmental impacts associated with the operation of Salem Generating Station Unit Nos. 1 and 2. Certain environmental issues were identified which required study or license conditions to resolve and to assure adequate protection of the environment. The Appendix B Environmental Technical Specifications (ETS) issued with the operating license included discharge restrictions and monitoring programs related to aquatic and terrestrial resources.

1. Protection of the aquatic environment by limiting the thermal characteristics of the discharge.

2. Protection of the aquatic environment from biocide used in plant operations.

3. Protection of the aquatic environment from suspended solids and changes in pH in releases from the non-radioactive liquid waste disposal system.

4. Surveillance programs for dissolved gases, suspended solids, chemical releases, and the general aquatic ecological surveys to establish impact of plant operation on the biotic environment.

2.1 Aquatic Issues

Requirements for study of station intake and discharges effects were removed from the ETS by License Amendments 51 (Unit 1) and 18 Unit 2, dated March 14, 1983 and March 11, 1983, respectively. These issues now are addressed by the effluent limitations and monitoring requirements contained in the effective NJPDES Permit No. NJ0005622 issued by the State of New Jersey, and by the determination of the State of New Jersey on the Section 316(a) and (b) demonstration submitted by licensee. The NRC will rely on the State for regulation of matters involving water quality and aquatic biota.

2.2 Terrestrial Issues

Requirements for study of station effects on terrapins and raptors have been met.

3.0 Consistency Requirements

3.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such activities do not involve an unreviewed environmental question and do not involve a change in the EPP*. Changes in station design or operation performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by Section 3.3 are not subject to the requirements of this Section.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable nonradiological environmental effects are confined to the on-site areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activity and obtain prior NRC approval. When such activity involves a change in the EPP, such activity and change to the EPP may be implemented only in accordance with an appropriate license amendment as set forth in Section 5.3 of this EPP.

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* This provision does not relieve the licensee of the requirements of 10 CFR 50.59.

A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns: (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the FES-OL, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) as significant change in effluents or power level; or (3) a matter, not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have a significant adverse environmental impact.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include written evaluations which provide bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question or constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1.0. The licensee shall include as part of the Annual Environmental Operating Report (per Subsection 5.4.1) brief descriptions, analyses, interpretations, and evaluations of such changes, tests and experiments.

3.2 Reporting Related to the NJPDES Permit or the State Certification

Changes to, or renewals of, the NJPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change or renewal is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The licensee shall notify the NRC of changes to the effective NJPDES Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the NJPDES Permit at the same time the application is submitted to the permitting agency.

3.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, and local environmental regulations are not subject to the requirements of Section 3.1.

4.0 Environmental Conditions

4.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to plant operation shall be recorded and reported to the NRC within 24 hours followed by a written report per Subsection 5.4.2. The following are examples: excessive bird impaction events; onsite plant or animal disease outbreaks; mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973; fish kills or impingement events on the intake screens; increase in nuisance organisms or conditions; unanticipated or emergency discharge of waste water or chemical substances.

No routine monitoring programs are required to implement this condition.

4.2 Environmental Monitoring

4.2.1 Aquatic Monitoring

The certifications and permits required under the Clean Water Act provide mechanisms for protecting water quality and, indirectly, aquatic biota. The Nuclear Regulatory Commission (NRC) will rely on the decisions made by the State of New Jersey under the authority of the Clean Water Act and, in the case of sea turtles and shortnose sturgeon, decisions made by the National Marine Fisheries Service (NMFS) under the authority of the Endangered Species Act, for any requirements pertaining to aquatic monitoring.

In accordance with Section 7(a) of the Endangered Species Act, on May 14, 1993, the National Marine Fisheries Service issued a Section 7 Consultation Biological Opinion related to the operation of Salem Unit 1 and 2 Generating Stations. This Section 7 Consultation entitled, "Reinitiation of a consultation in accordance with Section 7(a) of the Endangered Species Act regarding continued operation of the Salem and Hope Creek Nuclear Generating Stations on the eastern shore of the Delaware River in New Jersey," concluded that "...continued operation is not likely to jeopardize the continued existence of listed species."

PSEG Nuclear LLC shall adhere to the specific requirements within the Incidental Take Statement, to the Biological Opinion. Changes to the incidental take statement must be proceeded by consultation between the NRC, as the authorizing agency, and NMFS.

The Conservation Recommendation, to the Biological Opinion suggests conservation recommendations for implementation by Salem Generating Station. The Station shall implement these recommendations to the satisfaction of the NRC and National Marine Fisheries Service.

4.2.2 Terrestrial Monitoring

Terrestrial monitoring is not required.

5.0 Administrative Procedures

5.1 Review

The licensee shall provide for review of compliance with the EPP. The review shall be conducted independently of the individual or groups responsible for performing the specific activity. A description of the organization structure utilized to achieve the independent review function and results of the review activities shall be maintained and made available for inspection.

5.2 Records Retention

Records and logs relative to the environmental aspects of station operation shall be made and retained in a manner convenient for review and inspection. These records and logs shall be made available to NRC on request.

Records of modifications to station structures, systems and components determined to potentially affect the continued protection of the environmental shall be retained for the life of the station. All other records, data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Requests for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revision to the EPP.

5.4 Plant Reporting Requirements

5.4.1 Routine Reports

An Annual Environmental Operating Report describing implementation of this EPP for the previous year shall be submitted to the NRC prior to May 1 of each year.

The report shall include summaries and analyses of the results of the environmental protection activities required by Subsection 4.2 (if any) of this EPP for the report period, including a comparison with related preoperational studies, operational controls (as appropriate), and previous nonradiological environmental monitoring reports, and an assessment of the observed impacts of the plant operation on the environment. If harmful effects or evidence of trends toward irreversible damage to the environment are observed, the licensee shall provide a detailed analysis of the data and a proposed course of mitigating action.

The Annual Environmental Operating Report shall also include:

(1) A list of EPP noncompliances and the corrective actions taken to remedy them.

(2) A list of all changes in station design or operation, tests, and experiments made in accordance with Subsection 3.1 which involved a potentially significant unreviewed environmental question.

(3) A list of nonroutine reports submitted in accordance with Subsection 5.4.2.

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing results shall be submitted as soon as possible in a supplementary report.

5.4.2 Nonroutine Reports

A written report shall be submitted to the NRC within 30 days of occurrence of a nonroutine event. The report shall: (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact, and plant operating characteristics; (b) describe the probable cause of the event; (c) indicate the action taken to correct the reported event; (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such report at the same time it is submitted to the other agency.

APPENDIX C
ADDITIONAL CONDITIONS
OPERATING LICENSE NO. DPR-70

PSEG Nuclear LLC, and the Exelon Generation Company, LLC, shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
192	The licensee is authorized to relocate certain Technical Specification requirements to licensee-controlled documents. Implementation of this amendment shall include the relocation of these technical specification requirements to the appropriate documents, as described in the licensee's application dated January 11, 1996, as supplemented by letters dated February 26, May 22, June 27, July 12, December 23, 1996, and March 17, 1997, and evaluated in the staff's safety evaluation attached to this amendment.	The amendment shall be implemented within 60 days from March 21, 1997.
194	The licensee is authorized to upgrade the initiation circuitry for the power operated relief valves, as described in the licensee's application dated January 31, 1997, as supplemented by letters dated March 14, April 8, and April 28, 1997, and evaluated in the staff's safety evaluation attached to this amendment.	The amendment shall be implemented prior to entry into Mode 3 from the current outage for Salem Unit 1.
196	Containment Fan Cooler Units The licensee shall complete all modifications associated with the amendment request concerning Containment Fan Cooler Units (CFCU) response time dated October 25, 1996, as described in the letters supplementing the amendment request dated December 11, 1996, January 28, March 27, April 24, June 3, and June 12, 1997, prior to entry into Mode 3 following refueling outage 12. All modifications made in support of this amendment request and described in the referenced sumittals shall be in conformance with the existing design basis for Salem Unit 1, and programmatic controls for tank monitoring instrumentation shall be as described in the letter dated April 24, 1997. Post modification testing and confirmatory analyses shall be as described in the letter dated March 27, 1997. Future changes to the design described in these submittals may be made in accordance with the provisions of 10 CFR 50.59. Further, the administrative controls associated with CFCU operability and containment integrity described in the letters dated March 27, and April 24, 1997 shall not be relaxed or changed without prior staff review until such time as the license has been amended to include the administrative controls as technical specification requirements.	The amendment shall be implemented prior to entry into Mode 3 from the current outage for Salem Unit 1.
198	The licensee shall perform an evaluation of the containment liner anchorage by November 30, 1997, for the loading induced on the containment liner during a Main Steam Line Break event to confirm the assumptions provided in the Preliminary Safety Analysis Report and Updated Final Safety Analysis Report.	The amendment shall be implemented within 30 days from July 17, 1997.

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ADDITIONAL CONDITIONS OPERATING LICENSE NO. DPR-75 APPENDIX C

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

PSEG NUCLEAR LLC
EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-311

SALEM NUCLEAR GENERATING STATION, UNIT NO. 2

FACILITY OPERATING LICENSE

Amendment No. 227
License No. DPR-75

1. The Nuclear Regulatory Commission (the Commission) having found that:

   A. The application for license filed by Public Service Electric and Gas Company for itself and the Philadelphia Electric Company, Delmarva Power and Light Company and Atlantic City Electric Company complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the Salem Nuclear Generating Station, Unit No. 2 (facility) has been substantially completed in conformity with Construction Permit No. CPPR-53 and the application, as amended, the provisions of the Act and the regulations of the Commission;

   C. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the regulations of the Commission;

   D. There is reasonable assurance: (i) that the activities authorized by this operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   E. PSEG Nuclear LLC is technically qualified to engage in the activities authorized by this operating license in accordance with the Commission's regulations set forth in 10 CFR Chapter I;

F. The licensees are financially qualified to engage in the activities authorized by this license in accordance with the Commission's regulations set forth in 10 CFR Chapter I;

G. The licensees have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

H. The issuance of this operating license will not be inimical to the common defense and security or to the health and safety of the public;

I. After weighing the environmental, economic, technical and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Facility Operating License No. DPR-75 subject to the conditions for protection of the environment set forth herein is in accordance with 10 CFR Part 50 Appendix D of the Commission's regulations and all applicable requirements have been satisfied; and

J. The receipt, possession, and use of source, byproduct and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70.

2. Pursuant to approval by the Nuclear Regulatory Commission at meetings on January 14, 1981, April 28, 1981, and May 19, 1981, the License for Fuel-Loading and Low-Power Testing issued on April 18, 1980 is superseded by Facility Operating License No. DPR-75 hereby issued to PSEG Nuclear LLC, and the Exelon Generation Company LLC (Exelon Generation Company), (the licensees), to read as follows:

A. This license applies to the Salem Nuclear Generating Station, Unit No. 2, a pressurized water nuclear reactor and associated equipment (the facility), owned by the licensees. The facility is located on the southern end of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township in Salem County, New Jersey and is described in the Final Safety Analysis Report as supplemented and amended and the Environmental Report as supplemented and amended.

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

(1) PSEG Nuclear LLC, and the Exelon Generation Company to possess the facility at the designated location in Salem County, New Jersey, in accordance with the procedures and limitations set forth in the license;

(2) PSEG Nuclear LLC, pursuant to Section 104b of the Act and 10 CFR part 50, "Domestic Licensing of Production and Utilization Facilities," to possess, use and operate the facility at the designated location in Salem County, New Jersey, in accordance with the limitations set forth in this license;

(3) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source or special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration and as fission detectors in amounts as required;

(5) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate the facility at steady state reactor core power levels not in excess of 3459 megawatts (thermal).

(2) Technical Specifications and Environmental Plan

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 266, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Special Low Power Test Program

PSE&G shall complete the training portion of the Special Low Power Test Program in accordance with PSE&G's letter dated September 5, 1980 and in accordance with the Commission's Safety Evaluation Report "Special Low Power Test Program", dated August 22, 1980 (See Amendment No. 2 to DPR-75 for the Salem Nuclear Generating Station, Unit No. 2) prior to operating the facility at a power level above five percent.

Within 31 days following completion of the power ascension testing program outlined in Chapter 13 of the Final Safety Analysis Report, PSE&G shall perform a boron mixing and cooldown test using decay heat and Natural Circulation. PSE&G shall submit the test procedure to the NRC for review and approval prior to performance of the test. The results of this test shall be submitted to the NRC prior to starting up following the first refueling outage.

(4) Initial Test Program

PSE&G shall conduct the post-fuel-loading initial test program (set forth in Chapter 13 of the Final Safety Analysis Report, as amended) without making any major modifications of this program unless modifications have been identified and have received prior NRC approval. Major modifications are defined as:

(a) Elimination of any test identified in Chapter 13 of the Final Safety Analysis Report, as amended, as essential;

(b) Modification of test objectives, methods or acceptance criteria for any test identified in Chapter 13 of the Final Safety Analysis Report, as amended, as essential;

(c) Performance of any test at a power level different by more than five percent of rated power from there described; and

(d) Failure to complete all tests included in the described program (planned or scheduled for power levels up to the authorized power level) prior to exceeding a core burnup of 120 effective full power days.

(5) Instrument Trip Setpoints

PSE&G shall submit for NRC review within six months of the date of issuance of this operating license the following values for each Reactor Protection System and Engineered Safety Features instrumentation channel:

(a) the Technical Specification allowable value (the Technical Specification trip setpoint plus the instrument drift assumed in the accident analysis);

(b) the instrument drift assumed to occur during the interval between Technical Specification surveillance tests;

(c) the components of the cumulative instrument bias; and

(d) the maximum margin between the Technical Specification trip setpoint and the trip value assumed in the accident analysis.

(6) SMII-6 Open Items List

Prior to exceeding five percent rated thermal power, PSE&G will resolve to the satisfaction of the NRC's Office of Inspection and Enforcement all remaining construction and testing deficiencies in the SMII-6 Open Items List designated for completion prior to the commencement of power range testing. All listed items deferred beyond the commencement of power range testing will be subject to review by NRC Region I inspectors.

(7) Compliance With Regulatory Guide 1.97

By June 1, 1983, PSE&G shall implement to the satisfaction of the NRC the provisions of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," as modified by PSE&G's commitments to NUREG-0588 and NUREG-0737.

(8) Snubbers

(a) Within 4 months after issuance of the license, PSE&G shall provide a Technical Specification listing of mechanical snubbers. In the interim, PSE&G will conduct a comprehensive mechanical snubber inspection program implemented by plant instructions.

(b) The functional testing of hydraulic and mechanical snubbers in accordance with Technical Specification 3.7.9 shall commence with the first refueling outage. The initial functional testing shall be completed prior to resuming power operation following the first refueling outage.

(9) Environmental Qualification (Section 3.11, Supplement 5)*

PSE&G shall take the following remedial actions, or alternative actions acceptable to the NRC, with regard to the environmental qualification requirements for Class IE equipment:

(a) No later than June 30, 1982, the wide-range resistance temperature detectors for the reactor coolant system shall be qualified for radiation exposure for the 40-year plant life and appropriate exposure condition due to design basis accidents. Pending completion of such qualification and acceptance by the NRC, PSE&G shall replace each of these detectors at each refueling outage.

(b) Prior to completion of the first refueling outage or June 30, 1982, whichever is earliest, PSE&G shall replace the Scotchcast No. 9 resin seals, used at the electrical connection interface on the NAMCO limit switches, with Conax Electric Conduction Seal Assemblies.

(c) By no later than June 30, 1982, all safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: "Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors" (DOR Guidelines); or NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979.

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*References are to the appropriate sections of the Safety Evaluation Report (NUREG-0517) and its supplements.

(d) Complete and auditable records must be available and maintained at a central location which describe the environmental qualification method used for all safety-related electrical equipment in sufficient detail to document the degree of compliance with the DOR Guidelines or NUREG-0588. Such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified to document complete compliance by June 30, 1982.

(e) Within 90 days of receipt of the equipment qualification safety evaluation, the licensee shall either (i) provide missing documentation identified in Sections 3 and 4 of the equipment qualification safety evaluation which will demonstrate compliance of the applicable equipment with NUREG-0588, or (ii) commit to corrective actions which will result in documentation of compliance of applicable equipment with NUREG-0588 not later than June 30, 1982.

(10) Fire Protection

PSEG Nuclear LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report, as approved in the NRC Safety Evaluation Report, dated November 20, 1979, and in its supplements, and in the NRC Safety Evaluation dated January 7, 2004, subject to the following provision:

PSEG Nuclear LLC may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

PAGES 8, 9, AND 10 ARE INTENTIONALLY BLANK

(11) Containment Isolation (Section 6.2.3, Supplements 4 and 5)

Within 90 days after issuance of the license, PSE&G shall demonstrate to the satisfaction of the NRC that the present containment isolation provisions for the main feedwater lines comply with the requirements of General Design Criterion 57 under all postulated accident conditions, or propose a design change that will achieve compliance. If necessary, the design change shall be implemented during the first refueling outage.

(12) Main Condenser (Section 14.0, Supplement 4)

Prior to exceeding 50 percent power, PSE&G shall complete the preoperational testing of the remaining three of six circulators to be tested in the main condenser for the circulating water system.

(13) River Traffic Accidents (Section 2.2.1, Supplement 1)

PSE&G shall also report for the Salem facility any information reported for the Hope Creek facility relating to circumstances which suggest that the risk from flammable gas clouds (resulting from river traffic accidents on the Delaware River) varies significantly from that previously considered.

(14) <u>Waterhammer Test (Appendix C, A-1, Supplement 4 and Section 22.2, II.E.1.1, Supplement 5)</u>

Prior to exceeding 90 percent power, PSE&G shall perform a test program to show that unacceptable waterhammer damage will not result from anticipated feedwater transients to the steam generator. Prior to performing the test program, PSE&G shall obtain NRC approval of the test procedures.

(15) Prior to resuming power operation following the first refueling outage:

(a) <u>Control Rod Guide Thimble (Section 4.2.2, Supplement 4)</u>

PSE&G shall submit the details of the inspection program for control rod guide thimble tube wall wear for NRC approval.

(c) <u>Pressure Isolation Valves (Section 5.3.2, Supplement 5)</u>

PSE&G shall install leak test connections on the pressure isolation valves; until installation of the leak test connections, PSE&G may substitute multiple valve leak tests for Technical Specification 3.4.7.2.f, such that the cumulative leakage from two valves in parallel lines shall not exceed two gallons per minute, and the cumulative leakage from three valves in parallel lines shall not exceed three gallons per minute.

(d) <u>Diesel Generator Reliability (Section 8.3.4, Supplement 5)</u>

PSE&G shall implement the following design and procedural modifications with respect to diesel generator reliability:

(i) Complete a formal training program for all the mechanical and electrical maintenance and quality control personnel, including supervisors, who are responsible for the maintenance and availability of the diesel generators. The depth and quality of this training program shall be at least equivalent to that of training programs normally conducted by major diesel engine manufacturers.

(ii) Develop operating procedures that require loading the diesel engine to a minimum of 25 percent of full load for one hour after eight hours of continuous no load operation or as recommended by the engine manufacturer.

(e) Containment Sump Model Test (Appendix C, A-43, Supplement 4)

PSE&G shall submit the confirmatory results of the containment sump model test program, along with a description of any sump modifications resulting from the tests.

(f) Under-Voltage Protection (Section 8.4.1, Supplement 4)

PSE&G shall install a second level of undervoltage protection for the emergency buses.

(g) Reactor Containment Electrical Penetrations (Section 8.4.3., Supplement 4)

PSE&G shall add a fuse in series with the primary device of each one of 12 circuits fed from 230 volt ac motor control centers to provide backup protection for reactor containment electrical penetrations. Each fuse shall be located in an independent compartment in the control center of the present primary device.

(16) Loss of Non-Class 1E Instrumentation and Control Power Bus During Operation (Section 7.9, Supplement 5)

PSE&G shall implement the design modifications identified in the PSE&G letter dated July 31, 1980 prior to resuming power operation following the first refueling outage.

(17) Turbine Inspection (Section 3.5.1, Supplement 5)

Prior to resuming power operation following the second refueling outage, PSE&G shall subject the low pressure turbines to an inservice inspection. The inspection shall consist of visual and volumetric examinations. The visual examination shall be applied to 100 percent of all the accessible surface of the rotors, discs and blading. The volumetric examination shall use an ultrasonic technique to fully examine the bore and keyway region of the discs in each low pressure turbine.

The inspection results and evaluation of this inservice inspection shall be reported to the NRC and shall be accepted by the NRC prior to startup following the second refueling outage.

(18) Vibration Dynamics Effects Test (Section 3.9.1, SER)

PSE&G shall conduct a preoperational vibration dynamic effects test program for all ASME 1, 2 and 3 piping systems and piping restraints during startup test programs and initial operation.

(19) Differential Pressure Baseline Data (Part II, Section I.G, Supplement 4)

PSE&G shall obtain baseline data regarding differential pressure across the elbow pressure taps in each reactor coolant loop for various pump combinations during startup and initial operation.

(20) Engineered Safety Feature Reset Controls (Section 7.10, Supplement 5)

In conformance with IE Bulletin 80-06, PSE&G shall correct the reset actions for the two sets of valves identified in the PSE&G letter dated June 13, 1980, as corrected by the PSE&G letter dated July 18, 1980, prior to operating the facility at a power level above five percent. PSE&G shall also perform the additional testing required by IE Bulletin 80-06 prior to operation above five percent power.

(21) Sump Performance (Section 6.3.3, Supplement 5)

(a) Prior to resuming power operation following the first refueling outage, PSE&G shall provide a detailed survey of insulation materials.

(b) Prior to operation above five percent power, control room operators shall be trained in the recognition and mitigation of LPI performance degradation.

(22) Radiation Protection Organization (Section 12.0, Supplement 5)

PSE&G shall complete the reorganization actions and programs associated with radiation protection no later than November 1, 1981.

(23) Category I Masonry Walls (Section 3.8.3, Supplement 5)

(a) Prior to operation above five percent power, PSE&G shall submit the information requested in the NRC letter dated January 8, 1981.

(b) Prior to startup following the first refueling, PSE&G shall resolve the difference between the staff criteria and the criteria used by PSE&G to the satisfaction of the NRC and implement the required fixes that might result from such a resolution.

(24) TMI Action Plan Conditions (Section 22.2, Supplement 5)

Unless otherwise noted, each of the following conditions references the appropriate section of Supplement No. 5 to the Safety Evaluation Report (NUREG-0517) for the Salem Nuclear Generation Station, Unit 2, dated January 1981 and shall be completed to the satisfaction of the NRC by the times indicated.

(a) DELETED

(b) Short-Term Accident Analysis and Procedure Revision (Section 22.2, I.C.1 and I.C.8)

The operators shall be briefed on the revisions to the emergency operation instruction within 30 effective full power days of operation.

(c) Auxiliary Feedwater System Reliability Evaluation (Section 22.2, II.E.1.1)

(i) PSE&G shall install auxiliary feedwater storage tank level indications and alarms in accordance with the PSE&G letter of May 5, 1980 prior to startup after the first refueling.

(ii) PSE&G shall perform a 48-hour endurance test on all auxiliary feedwater system pumps prior to operation at 100 percent power. PSE&G shall provide a report on the results of these tests to NRC within 60 days of completion of the tests.

(iii) PSE&G shall resolve to NRC's satisfaction the issue concerning time available for operator action to prevent pump damage prior to operation above five percent power.

(d) Upgrade Emergency Preparedness (Section 22.2, III.A.1.1 and Section 22.3, III.A.2)

(i) No later than 90 days from the date of issuance of this license, PSE&G shall report to the NRC the status of any items related to emergency preparedness identified by FEMA or the NRC as requuiring further action.

(ii) PSE&G shall provide meteorological and dose assessment remote interrogation capability to meet the criteria of Appendix 2, NUREG-0654, Revision 1 as follows: (a) a functional description of upgraded capabilities by January 1, 1982, (b) installation of hardware and software by July 1, 1982 provided that NRC approval is received by four months prior to that time and (c) full operational capability by October 1, 1982.

(iii) PSE&G shall provide substantiation that the back-up source of meteorological information from the NWS Office, Greater Wilmington Airport adequately characterizes the site conditions with respect to wind direction and wind speed by July 1, 1981.

(iv) PSE&G shall provide substantiation that uncertainties associated with plume trajectory prediction, associated with the occurrence of sea-land breeze circulations within the plume exposure pathway zone, are compatible with the planned recommendations for protective actions that would be based upon such projections by July 1, 1981.

(e) Primary Coolant Sources Outside Containment (Section 22.2, III.D.1.1)

(i) For those systems in which leakage is measured during shutdown, PSE&G shall make and report leak rate measurements prior to initial startup.

(ii) For those systems in which leakage is measured during operations, PSE&G will make and report leak rate measurements within 60 effective full-power days of plant operation.

(25) TMI Action Plan Dated Conditions (Section 22.3, Supplement 5)

Each of the following conditions references the appropriate section of Supplement No. 5 to the Safety Evaluation Report (NUREG-0517) for the Salem Nuclear Generating Station, dated January 1981, and shall be completed to the satisfaction of the NRC by the times indicated.

(a) Short-Term Accident Analysis and Procedure Revision (Section 22.3, I.C.1)

PSE&G shall implement the requirements of Item I.C.1 specified in NUREG-0737, "Clarification of TMI Action Plan Requirements," no later than the implementation dates established in NUREG-0737.

(b) Reactor Coolant System Vents (Section 22.3, II.B.1)

PSE&G shall submit procedural guidelines for and a description of the reactor coolant system vents by July 1, 1981. The reactor coolant system vents shall be installed no later than July 1, 1982.

(c) Plant Shielding (Section 22.3, II.B.2)

PSE&G shall complete modifications to assure adequate access to vital areas and protection of safety equipment following an accident resulting in a degraded core not later than January 1, 1982.

(d) Deleted

(e) Relief, Safety and Block Valve Test Requirements (Section 22.3, II.D.1)

PSE&G shall qualify the reactor coolant system relief, safety and block valves under expected operating conditions for design basis transients and accidents in accordance with the plant-specific requirements and schedules established in NUREG-0737, "Clarification of TMI Action Plan Requirements."

(f) Auxiliary Feedwater Initiation and Indication (Section 22.3, II.E.1.2)

PSE&G shall upgrade, as necessary, automatic initiation of the auxiliary feedwater system and indication of auxiliary feedwater flow to each steam generator to safety grade quality no later than July 1, 1981.

(g) Containment Isolation Dependability (Section 22.3, II.E.4.2)

(i) PSE&G shall reduce the containment setpoint pressure that initiates containment isolation for nonessential penetrations to the minimum compatible with normal operating conditions no later than July 1, 1981.

(ii) PSE&G shall install a high radiation isolation signal on the containment purge and vent isolation valves no later than July 1, 1981.

(h) Additional Accident Monitoring Instrumentation (Section 22.3, II.F.1)

PSE&G shall install and demonstrate the operability of instruments for continuous indication in the control room of the following variables. Each item shall be completed by the specified date in the condition:

(i) Containment pressure from minus five psig to three times the design pressure of the containment no later than January 1, 1982;

(ii) Containment water level from (i) the bottom to the top of the containment sump, and (ii) the bottom of the containment to an elevation equivalent to a 600,000 gallon capacity no later than July 1, 1981;

(iii) Containment atmosphere hydrogen concentration from 0 to 10 volume percent no later than January 1, 1982;

2.C(25)(h)(iv)

Containment gamma radiation up to 10^7 rad/hr. at the first outage of sufficient duration but no later than prior to startup following the first refueling outage; and

(v) Noble gas effluent from each potential release point from normal concentrations up to 10^5 uCi/cc (Xe-133) no later than prior to startup following the first refueling outage.

PSE&G shall provide the capability to continuously sample gaseous effluents and analyze these samples no later than prior to startup following the first refueling outage.

Until the above installation is completed, PSE&G shall use interim monitoring procedures and equipment.

PSE&G shall provide the capability to continuously sample gaseous effluents and analyze these samples no later than January 1, 1982.

Until the above installation is completed, PSE&G shall use interim monitoring procedures and equipment.

(i) Inadequate Core Cooling Instruments (Section 22.3, II.F.2)

PSE&G shall install and demonstrate the operability of additional instruments or controls needed to supplement installed equipment in order to provide unambiguous, easy-to-interpret indication of inadequate core cooling at the first outage of sufficient duration but no later than prior to startup following the first refueling outage.

(j) Thermal Mechanical Report (Section 22.3, II.K.2.13)

PSE&G shall submit a detailed analysis of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater no later than January 1, 1982.

(k) Analysis of Voiding Potential (Section 22.3, II.K.2.17)

PSE&G shall analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients. PSE&G shall submit this analysis no later than January 1, 1982.

(l) Sequential Auxiliary Feedwater Flow Analysis (Section 22.3, II.K.2.19)

PSE&G shall provide a benchmark analysis of sequential auxiliary feedwater (AFW) flow to the steam generators following a loss of main feedwater no later than January 1, 1982.

(m) Effect of Loss of Alternating-Current Power on Pump Seals (Section 22.3, II.K.3.25)

PSE&G shall determine, by analysis or experiment, the consequences of a loss of cooling water to the reactor coolant pump seals. PSE&G shall submit the results of the evaluation and proposed modifications no later than January 1, 1982.

(n) Revised Small-Break Loss-of-Coolant-Accident Methods (Section 22.3, II.K.3.30)

PSE&G shall comply with the requirements of this position as specified in NUREG-0737, "Clarification of TMI Action Plan Requirements."

(o) Compliance With 10 CFR Part 50.46 (Section 22.3, II.K.3.31)

PSE&G shall perform plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) to show compliance with 10 CFR Part 50.46. PSE&G shall submit these calculations by January 1, 1983, or one year after NRC approval of LOCA analysis models, whichever is later, only if model changes have been made.

(p) Emergency Support Facilities (Section 22.3 III.A.1.2)

PSE&G shall maintain in effect an interim Technical Support Center and an interim Emergency Operations Facility until such time as the final facilities are complete.

(26) Additional Conditions

The Additional Conditions contained in Appendix C, as revised through Amendment No. 227, are hereby incorporated into this license. PSEG Nuclear LLC shall operate the facility in accordance with the Additional Conditions.

(27) PSE&G to PSEG Nuclear LLC License Transfer Conditions

a. PSEG Nuclear LLC shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application, the requirements of the Order Approving Transfer of License and Conforming Amendment, dated February 16, 2000, and the related Safety Evaluation dated February 16, 2000.

b. The decommissioning trust agreement shall provide that:

1) The use of assets in both the qualified and non-qualified funds shall be limited to expenses related to decommissioning of the unit as defined by the NRC in its regulations and issuances, and as provided in the unit's license and any amendments thereto. However, upon completion of decommissioning, as defined above, the assets may be used for any purpose authorized by law.

2) Investments in the securities or other obligations of PSE&G or affiliates thereof, or their successors or assigns, shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants shall be prohibited.

3) No disbursements or payments from the trust shall be made by the trustee until the trustee has first given the NRC 30 days notice of the payment. In addition, no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation.

4) The trust agreement shall not be modified in any material respect without prior written notification to the Director, Office of Nuclear Reactor Regulation.

5) The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(3) of the Federal Energy Regulatory Commission's regulations.

c. PSEG Nuclear LLC shall not take any action that would cause PSEG Power LLC or its parent companies to void, cancel, or diminish the commitment to fund an extended plant shutdown as represented in the application for approval of the transfer of this license from PSE&G to PSEG Nuclear LLC.

(28) Exelon Generation Company shall provide to the Director of the Office of Nuclear Reactor Regulation a copy of any application, at the time it is filed, to transfer (excluding grants of security interests or liens) from Exelon Generation Company to its direct or indirect parent, or to any other affiliated company, facilities for the production, transmission, or distribution of electric energy having a depreciated book value exceeding ten percent (10%) of Exelon Generation Company's consolidated net utility plant, as recorded on Exelon Generation Company's books of account.

(29) Exelon Generation Company shall have decommissioning trust funds for Salem, Unit 2, in the following minimum amount on the closing date of the license transfer to it:

Salem, Unit 2 $45,059,302

(30) The decommissioning trust agreement for Salem, Unit 2, shall be subject to the following:

(a) The decommissioning trust agreement must be in a form acceptable to the NRC.

(b) With respect to the decommissioning trust fund, investments in the securities or other obligations of Exelon Corporation or affiliates thereof, or their successors or assigns are prohibited. Except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants are prohibited.

(c) The decommissioning trust agreement for Salem, Unit 2, must provide that no disbursements or payments from the trust shall be made by the trustee unless the trustee has first given the Director, Office of Nuclear Reactor Regulation, 30 days prior written notice of payment. The decommissioning trust agreement shall further contain a provision that no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the NRC.

(d) The decommissioning trust agreement must provide that the agreement can not be amended in any material respect without prior written consent of the Director, Office of Nuclear Reactor Regulation.

(e) The appropriate section of the decommissioning trust agreement shall state that the trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations.

(31) Exelon Generation Company shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for approval of the transfer of its ownership interest in Salem, Unit 2, license and the requirements of the Order approving the transfer, and consistent with the safety evaluation supporting the Order.

(32) <u>Mitigation Strategy</u>

The licensee shall develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:

1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:

1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:

1. Water spray scrubbing
2. Dose to onsite responders

Revised by letter dated August 9, 2007

D. An exemption from certain requirements of Appendix J to 10 CFR Part 50 is described in the Office of Nuclear Reactor Regulation's Safety Evaluation Report, Supplement No. 4. This exemption was authorized by law and will not endanger life of property or the common defense and security and is otherwise in the public interest. The exemption, therefore, remains in effect. The granting of the exemption was authorized with the issuance of the License for Fuel-Loading and Low-Power Testing, dated April 18, 1980. The facility will operate, to the extent authorized herein, in conformity with the application as amended, the provisions of the Act, and the regulations of the Commission.

E. The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54 (p). The plans, submitted by letter dated May 19, 2006, are entitled: "Salem-Hope Creek Nuclear Generating Station Security Plan," "Salem-Hope Creek Nuclear Generating Station Security Training and Qualification Plan," and "Salem-Hope Creek Nuclear Generating Station Security Contingency Plan." The plans Contain Safeguards Information protected under 10 CFR 73.21.

F. A temporary exemption from General Design Criterion 57 found in Appendix A to 10 CFR Part 50 is described in the Office of Nuclear Reactor Regulation's Safety Evaluation Report, Supplement No. 5, Section 6.2.3.1. This Exemption is authorized by law and will not endanger life or property or the common defense and security and is otherwise in the public interest. The exemption, therefore, is hereby granted and shall remain in effect through the first refueling outage as discussed in Section 6.2.3.1 of Supplement 5 to the Safety Evaluation Report. The granting of the exemption is authorized with the issuance of the Facility Operating License, dated May 20, 1981. The facility will operate, to the extent authorized herein, in conformity with the application as amended, the provisions of the Act, and the regulations of the Commission.

G. This license is subject to the following additional condition for the protection of the environment:

Before engaging in additional construction or operational activities which may result in an environmental impact that was not evaluated by the Commission, PSEG Nuclear LLC shall prepare and record an environmental evaluation of such activity. When the evaluation indicates that such activity may result in a significant adverse environmental impact that was not evaluated, or that is significantly greater than that evaluated in the Final Environmental Statement or any addendum thereto, PSEG Nuclear LLC shall provide a written evaluation of such activities and obtain prior approval from the Director of Nuclear Reactor Regulation.

H. If PSEG Nuclear LLC plans to remove or to make significant changes in the normal operation of equipment that controls the amount of radioactivity in effluents from the Salem Nuclear Generation Station, the NRC shall be notified in writing regardless of whether the change affects the amount of radioactivity in effluents.

I. PSEG Nuclear LLC shall report any violations of the requirements contained in Section 2, Items C. (3) through C. (25), E..F.. and G of this license within 24 hours by telephone and confirmed by telegram, mailgram, or facsimile transmission to the Director of the Regional Office, or his designee, no later than the first working day following the violation, with a written-followup report within 14 days.

J. The licensees shall immediately notify the Commission of any accident at this facility which could result in an unplanned release of quantities of fission products in excess of allowable limits for normal operation established by the Commission.

K. The licensees shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended to cover public liability claims.

L. The licensee is authorized to defer certain eighteen-month surveillance items from the dates required by Technical Specifications 4.0.2(a) and 4.7.10.2(c). These surveillances shall be completed prior to startup following the first refueling outage. The provisions of Technical Specifications 4.0.2(b) and 4.7.10.2(c) are not changed. The affected items are identified in the Safety Evaluation accompanying Amendment No. 14 issued October 22, 1982 and this license change.

M. This license is effective as of the date of the issuance and shall expire at midnight April 18, 2020.

N. Relocated Technical Specifications

PSEG Nuclear LLC shall relocate certain technical specification requirements to licensee-controlled documents as described below. The location of these requirements shall be retained by the licensee.

a. This license condition approves the relocation of certain technical specification requirements to licensee-controlled documents (UFSAR), as described in the licensee's applications with the staff's safety evaluation approval and Amendment No. as noted below:

Licensee's Application	Safety Evaluations	Amendment Nos.
September 25, 1996	January 30, 1997	172

Implementation shall include the relocation of technical specifications requirements to the appropriate licensee-controlled document as identified in the licensee's application.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by Edson G. Case

Edson G. Case, Acting Director
Office of Nuclear Reactor Regulation

Attachment:
Appendices A & B

Date of Issuance: May 20, 1981

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DESIGN FEATURES

ADMINISTRATIVE CONTROLS

SECTION 1.0

DEFINITIONS

1.0 DEFINITIONS

DEFINED TERMS

1.1 The DEFINED TERMS of this section appear in capitalized type and are applicable throughout these Technical Specifications.

ACTION

1.2 ACTION shall be that part of a specification which prescribes remedial measures required under designated conditions.

AXIAL FLUX DIFFERENCE

1.3 AXIAL FLUX DIFFERENCE shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, display, and trip functions, and shall include the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever an RTD or thermocouple sensing element is replaced, the next required CHANNEL CALIBRATION shall include an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 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.

CONTAINMENT INTEGRITY

1.7 CONTAINMENT INTEGRITY shall exist when:

1.7.1 All penetrations required to be closed during accident conditions are either:

a. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

b. Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

1.7.2 All equipment hatches are closed and sealed,

1.7.3 Each air lock is OPERABLE pursuant to Specification 3.6.1.3,

1.7.4 The containment leakage rates are within the limits of Specification 3.6.1.2, and

1.7.5 The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

CORE ALTERATION

1.8 CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe conservative position.

CORE OPERATING LIMITS REPORT

1.9 The CORE OPERATING LIMITS REPORT (COLR) is the unit-specific document that provides core operating limits for the current operating reload cycle. These cycle-specific core operating limits shall be determined for each reload cycle in accordance with Specification 6.9.1.9. Unit operation within these operating limits is addressed in individual specifications.

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries per gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Federal Guidance Report No. 11 (FGR 11), "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion".

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half-lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

ENGINEERED SAFETY FEATURE RESPONSE TIME

1.12 The ENGINEERED SAFETY FEATURE RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

FREQUENCY NOTATION

1.13 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.2.

FULLY WITHDRAWN

1.13a FULLY WITHDRAWN shall be the condition where control and/or shutdown banks are at a position which is within the interval of 222 to 228 steps withdrawn, inclusive. FULLY WITHDRAWN will be established by the current reload analysis.

GASEOUS RADWASTE TREATMENT SYSTEM

1.14 A GASEOUS RADWASTE TREATMENT SYSTEM is any system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

IDENTIFIED LEAKAGE

1.15 IDENTIFIED LEAKAGE shall be:

a. Leakage (except Reactor Coolant Pump Seal Water Injection) into closed systems, such as pump seal or valve packing leaks that are captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE, or

c. Reactor coolant system leakage through a steam generator to the secondary system (primary-to-secondary leakage).

MEMBER(S) OF THE PUBLIC

1.16 MEMBER(S) OF THE PUBLIC shall be all those persons who are not occupationally associated with the plant. This category does not include employees of PSE&G, its contractors, or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational, or other purposes not associated with the plant.

OFFSITE DOSE CALCULATION MANUAL (ODCM)

1.17 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent controls and Radiological Environmental Monitoring programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.9.1.7 and 6.9.1.8 respectively.

OPERABLE - OPERABILITY

1.18 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s), and when all necessary attendant instrumentation, controls, normal or emergency electrical power source, cooling and seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its specified safety function(s) are also capable of performing their related support function(s).

OPERATIONAL MODE - MODE

1.19 An OPERATIONAL MODE (i.e., MODE) shall correspond to any one inclusive combination of core reactivity condition, power level and average reactor coolant temperature specified in Table 1.1.

PHYSICS TESTS

1.20 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and 1) described in Chapter 14 of the Updated FSAR, 2) authorized under the provisions of 10CFR50.59, or 3) otherwise by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.21 PRESSURE BOUNDARY LEAKAGE shall be leakage (except primary-to-secondary leakage) through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.22 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of radioactive waste.

PURGE - PURGING

1.23 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

QUADRANT POWER TILT RATIO

1.24 QUADRANT POWER TILT RATIO shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.25 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3459 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

REPORTABLE EVENT

1.27 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10CFR Part 50.

SHUTDOWN MARGIN

1.28 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be FULLY WITHDRAWN.

SITE BOUNDARY

1.29 The SITE BOUNDARY shall be that line beyond which the land is not owned, leased, or otherwise controlled by the licensee, as shown in Figure 5.1-3, and which defines the exclusion area as shown in Figure 5.1-1.

SOLIDIFICATION

1.30 Not Used

SOURCE CHECK

1.31 SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to either (a) an external source of increased radioactivity, or(b) an internal source of radioactivity (keep-alive source), or (c) an equivalent electronic source check .

STAGGERED TEST BASIS

1.32 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for (n) systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into (n) equal subintervals.

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

THERMAL POWER

1.33 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

UNIDENTIFIED LEAKAGE

1.34 UNIDENTIFIED LEAKAGE shall be all leakage (except Reactor Coolant Pump Seal Water Injection) which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.35 An UNRESTRICTED AREA shall be any area at or beyond the SITE BOUNDARY, access to which is not controlled by the licensee for purposes of protection of individuals from exposure to radiation and radioactive materials, or any area within the SITE BOUNDARY used for residential quarters or industrial, commercial, institutional, and/or recreational purposes.

VENTILATION EXHAUST TREATMENT SYSTEM

1.36 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine and radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.37 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

TABLE 1.1

OPERATIONAL MODES

MODE	REACTIVITY CONDITION, K_{eff}	THERMAL POWER*	AVERAGE COOLANT TEMPERATURE
1. POWER OPERATION	$\geq$ 0.99	> 5%	$\geq$ 350°F
2. STARTUP	$\geq$ 0.99	$\leq$ 5%	$\geq$ 350°F
3. HOT STANDBY	< 0.99	0	$\geq$ 350°F
4. HOT SHUTDOWN	< 0.99	0	350°F > T_{avg} > 200°F
5. COLD SHUTDOWN	< 0.99	0	$\leq$ 200°F
6. REFUELING**	$\leq$ 0.95	0	$\leq$ 140°F

* Excluding decay heat.

** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 6 months.
R	At least once per 18 months.
S/U	Prior to each reactor startup.
P	Prior to each release.
N.A.	Not applicable.

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and the highest operating loop coolant temperature (T_{avg}) shall not exceed the limits shown in Figures 2.1-1 for 4 loop operation.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of the highest operating loop average temperature and THERMAL POWER has exceeded the appropriate pressurizer pressure line, be in HOT STANDBY within 1 hour.

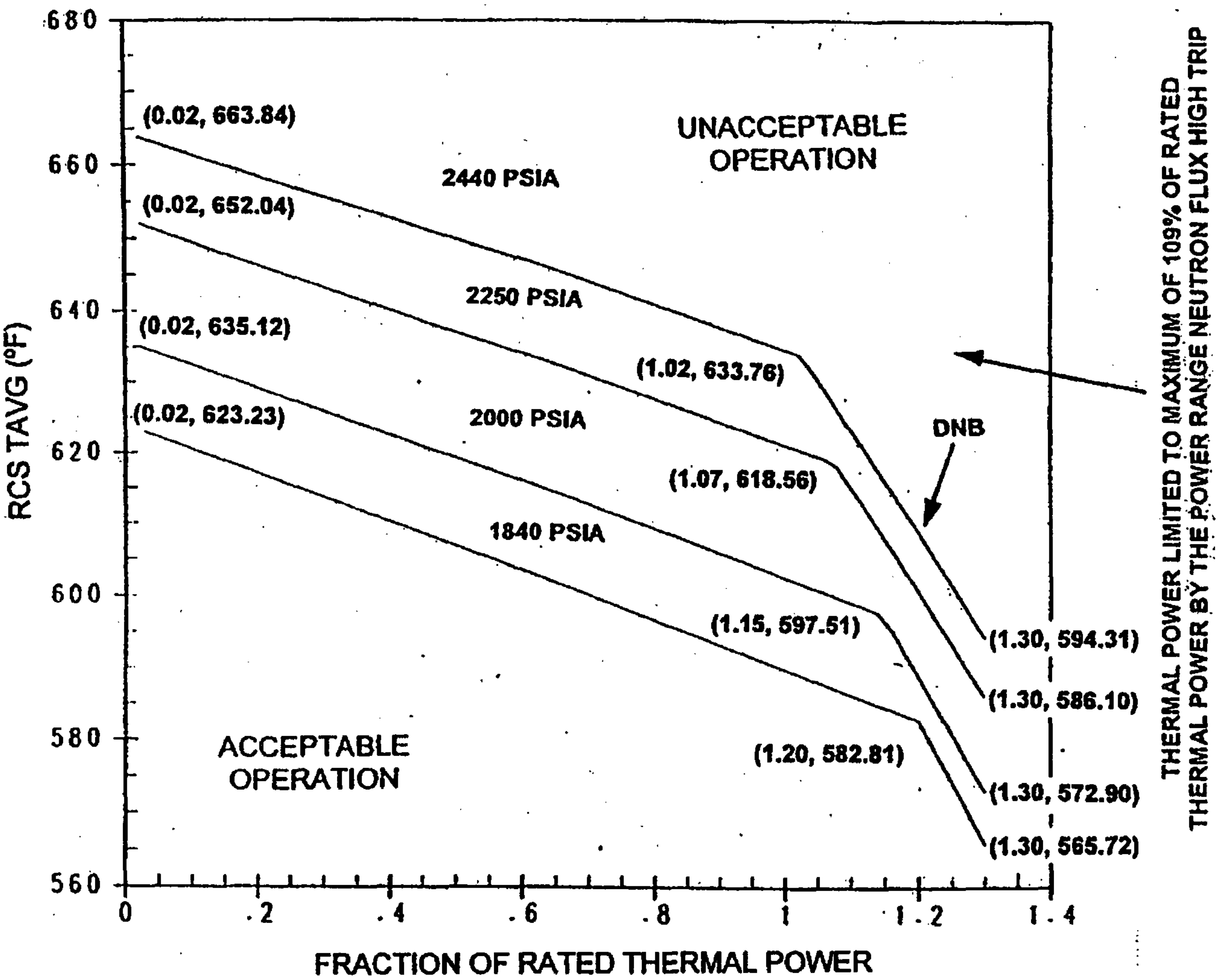

FIGURE 2.1-1 REACTOR CORE SAFETY LIMIT - FOUR LOOPS IN OPERATION

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2735 psig.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor trip system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: As shown for each channel in Table 3.3-1.

ACTION:

With a reactor trip system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not applicable	Not applicable
2. Power Range, Neutron Flux	Low setpoint - ≤ 25 % of RATED THERMAL POWER	Low Setpoint - ≤ 26% of RATED THERMAL POWER
	High Setpoint - ≤ 109% of RATED THERMAL POWER	High Setpoint - ≤ 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 second	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 second
4. Deleted		
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 counts per second	≤ 1.3 x 10^5 counts per second
7. Overtemperature ΔT	See Note 1	See Note 3
8. Overpower ΔT	See Note 2	See Note 4
9. Pressurizer Pressure--Low	≥ 1865 psig	≥ 1855 psig
10. Pressurizer Pressure--High	≤ 2385 psig	≤ 2395 psig
11. Pressurizer Water Level--High	≤ 92% of instrument span	≤ 93% instrument span
12. Loss of Flow	≥ 90% of design flow per loop*	≥ 89% of design flow per loop*

*Design flow is 82,500 gpm per loop.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level--Low-Low	≥ 14.0% of narrow range instrument span-each steam generator	≥ 13.0% of narrow range instrument span-each steam generator
14. Deleted		
15. Undervoltage-Reactor Coolant Pumps	≥ 2900 volts-each bus	≥ 2850 volts-each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 56.5 Hz - each bus	≥ 56.4 Hz - each bus
17. Turbine Trip		
A. Low Trip System Pressure	≥ 45 psig	≥ 45 psig
B. Turbine Stop Valve Closure	≤ 15% off full open	≤ 15% off full open
18. Safety Injection Input from ESF	Not Applicable	Not Applicable
19. Reactor Coolant Pump Breaker Position Trip	Not Applicable	Not Applicable

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION

NOTE 1: Overtemperature $\Delta T \leq \Delta T_o \left[K_1 - K_2\left(\frac{1+\tau_1 S}{1+\tau_2 S}\right)(T-T') + K_3(P-P') - f_1(\Delta I)\right]$

where: ΔT_o = Indicated ΔT at RATED THERMAL POWER

T = Average temperature, °F

T' = Reference T_{avg} at RATED THERMAL POWER $\leq$ 577.9°F

P = Pressurizer pressure, psig

P' = 2235 psig (indicated RCS nominal operating pressure)

$\frac{1+\tau_1 S}{1+\tau_2 S}$ = The function generated by the lead-lag controller for T_{avg} dynamic compensation

τ_1 & τ_2 = Time constants utilized in the lead-lag controller for T_{avg} τ_1 = 30 secs ±10%, τ_2 = 4 secs. ±10%

S = Laplace transform operator, Sec^{-1}

NOTATION (Continued)

Operation with 4 Loops

K_1 = 1.22
K_2 = 0.02037
K_3 = 0.001020

and f_1 (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -33 percent and +11 percent, f_1 (ΔI) = 0 where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of ($q_t - q_b$) exceeds -33 percent, the ΔT trip setpoint shall be automatically reduced by 2.34 percent of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of ($q_t - q_b$) exceeds +11 percent, the ΔT trip setpoint shall be automatically reduced by 2.37 percent of its value at RATED THERMAL POWER.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 1: Overpower $\Delta T \leq \Delta T_o \ [K_4 - K_5 \left[\frac{\tau_3 S}{1+\tau_3 S}\right] T - K_6 \ (T-T") - f_2(\Delta I)\ ]$

where: ΔT_o = Indicated ΔT at RATED THERMAL POWER

T = Average temperature, °F

$T"$ = Reference T_{avg} at RATED THERMAL POWER ≤ 577.9°F

K_4 = 1.09

K_5 = 0.02/°F for increasing average temperature and 0 for decreasing average temperature

K_6 = 0.00149/°F for $T > T"$; $K_6 = 0$ for $T \leq T"$

$\frac{\tau_3 S}{1+\tau_3 S}$ = The function generated by the rate lag controller for T_{avg} dynamic compensation

τ_3 = Time constant utilized in the rate lag controller for T_{avg} τ_3 = 10 secs. ±10%

S = Laplace transform operator, Sec^{-1}.

$f_2(\Delta I)$ = 0 for all ΔI

Note 3: The channel's maximum trip point shall not exceed its computed trip point by more than 1.1 percent.

Note 4: The channel's maximum trip point shall not exceed its computed trip point by more than 2.1 percent.

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through correlations which have been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, DNBR, decided as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The DNB design basis is as follows: uncertainties in the WRB-1 and WRB-2 correlations, plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, and computer codes are considered statistically such that there is at least a, 95 percent probability with 95 percent confidence level that DNBR will not occur on the most limiting fuel rod during Condition I and II events. This establishes a design DNBR value which must be met in plant safety analyses using values of input Parameters without uncertainties.

The curves of Figure 2.1-1 shows the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the design DNBR value, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

The curves are based on an enthalpy hot channel factor, $F^{RTP}_{\Delta H}$ and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^{N}_{\Delta H}$ at reduced power based on the expression:

$$F^{N}_{\Delta H} = F^{RTP}_{\Delta H} \, [1.0 + PF_{\Delta H} \, (1.0 - P)]$$

Where: $F^{RTP}_{\Delta H}$ is the limit at RATED THERMAL POWER in the Core Operating Limits Report (COLR).

$PF_{\Delta H}$ is the Power Factor Multiplier for $F^{N}_{\Delta H}$ specified in the COLR, and P is $\frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

These limiting heat flux conditions are higher than those calculated for the range of all control rod positions from FULLY WITHDRAWN to the maximum allowable control rod insertion assuming the axial power inbalance is within the limits of the f_1 (delta I) function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature delta T trips will reduce the setpoints to provide protection consistent with core safety limits.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor pressure vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plant which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The Reactor Coolant System piping and fittings are designed to ANSI B 31.1 1955 Edition while the valves are designed to ANSI B 16.5, MSS-SP-66-1964, or ASME Section III-1968, which permit maximum transient pressures of up to 120% (2985 psig) of component design pressure. The Safety Limit of 2735 psig is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at 3107 psig, 125% of design pressure, to demonstrate integrity prior to initial operation.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as-left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy).

The Trip Setpoints used in the bistables are based on the analytical limits stated in the UFSAR. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those Reactor Protection System (RPS) channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints and Allowable Values specified in the Technical Specification Limiting Conditions for Operation (LCO's) are conservatively adjusted with respect to the analytical limits. The methodology used to calculate the Trip Setpoints is consistent with Instrument Society of America standard ISA-S67.04-1982, which is endorsed via NRC Regulatory Guide 1.105, Rev. 2. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the safety analyses which demonstrate that safety limits are not violated remain valid (provided the unit is operated within the LCO's at the onset of any design basis event and the equipment functions as designed).

The Trip Setpoints and Allowable Values listed in the LCO's incorporate all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Power Range, Neutron Flux

The Power Range, Neutron Flux channel high setpoint provides reactor core protection against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The low set point provides redundant protection in the power range for a power excursion beginning from low power. The trip associated with the low setpoint may be manually bypassed when P-10 is active (two of the four power range channels indicate a power level of above approximately 9 percent of RATED THERMAL POWER) and is automatically reinstated when P-10 becomes inactive (three of the four channels indicate a power level below approximately 9 percent of RATED THERMAL POWER).

Power Range, Neutron Flux, High Rate

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of rod ejection events from any power level. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from partial power.

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor core protection during reactor startup. These trips provide redundant protection to the low setpoint trip of the Power Range, Neutron Flux channels. The Source Range Channels will initiate a reactor trip at about 10^{+5} counts per second unless manually blocked when P-6 becomes active. The Intermediate Range Channels will initiate a reactor trip at a current level proportional to approximately 25 percent of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit was taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

Overtemperature Δ T

The Overtemperature Δ T trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors (about 4 seconds), and pressure is within the range between the High and Low Pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. With normal axial power distribution, this reactor trip limit is always below the core safety limit as shown in Figure 2.1-1. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the reactor trip is automatically reduced according to the notations in Table 2.2-1.

Operation with a reactor coolant loop out of service below the 4 loop P-8 setpoint does not require reactor protection system setpoint modification because the P-8 setpoint and associated trip will prevent DNB during 3 loop operation exclusive of the Overtemperature delta T setpoint. Three loop operation above the 4 loop P-8 has not been evaluated and is not permitted.

Overpower Delta T

The Overpower delta T reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature delta T protection, and provides a backup to the High Neutron Flux trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors. No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Pressurizer Pressure

The Pressurizer High and Low Pressure trips are provided to limit the pressure range in which reactor operation is permitted. The High Pressure trip is backed up by the pressurizer code safety valves for RCS overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The Low Pressure trip provides protection by tripping the reactor in the event of a loss of reactor coolant pressure.

Pressurizer Water Level

The Pressurizer High Water Level trip ensures protection against Reactor Coolant System overpressurization by limiting the water level to a volume sufficient to retain a steam bubble and prevent water relief through the pressurizer safety valves. No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Loss of Flow

The Loss of Flow trips provide core protection to prevent DNB in the event of a loss of one or more reactor coolant pumps.

Above 11 percent of RATED THERMAL POWER, an automatic reactor trip will occur if the flow in any two loops drop below 90% of nominal full loop flow. Above 36% (P-8) of RATED THERMAL POWER, automatic reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. This latter trip will prevent the minimum value of the DNBR from going below the design DNBR value during normal operational transients.

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip provides core protection by preventing operation with the steam generator water level below the minimum volume required for adequate heat removal capacity. The specified setpoint provides allowance that there will be sufficient water inventory in the steam generators at the time of trip to allow for starting delays of the auxiliary feedwater system.

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The specified set points assure a reactor trip signal is generated before the low flow trip set point is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 0.9 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip set point is reached shall not exceed 0.3 seconds.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-9. Each of the turbine trips provide turbine protection and reduce the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

Safety Injection Input from ESF

If a reactor trip has not already been generated by the reactor protective instrumentation, the ESF automatic actuation logic channels will initiate a reactor trip upon any signal which initiates a safety injection. This trip is provided to protect the core in the event of a LOCA. The ESF instrumentation channels which initiate a safety injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The Reactor Coolant Pump Breaker Position Trip is an anticipatory trip which provides reactor core protection against DNB resulting from the opening of two or more pump breakers above P-7. This trip is blocked below P-7. The open/close position trip assures a reactor trip signal is generated before the low flow trip set point is reached. No credit was taken in the accident analyses for operation of this trip. The functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Protection system.

3.0.1 Compliance with the limiting Conditions for Operation contained in the succeeding specifications is required during the OPERATIONAL MODES or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the ACTION requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met except as provided in the associated ACTION requirements, within one hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in:

1. At least HOT STANDBY within the next 6 hours,
2. At least HOT SHUTDOWN within the following 6 hours, and
3. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual specifications.

3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time; or

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications, or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.5 DELETED

3.0.6 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL MODES or other specified conditions in the Applicability for individual Limiting Conditions for Operation, unless otherwise stated in the Surveillance Requirement. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the Limiting Condition for Operation. Failure to perform a Surveillance within the specified frequency shall be failure to meet the Limiting Condition for Operation, except as provided in Specification 4.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 Each Surveillance Requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25 percent of the specified surveillance interval.

4.0.3 If it is discovered that a Surveillance was not performed within its specified frequency, then compliance with the requirement to declare the Limiting Condition for Operation not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the Limiting Condition for Operation must immediately be declared not met and the applicable Actions must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the Limiting Condition for Operation must immediately be declared not met and the applicable Actions must be entered.

4.0.4 Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency, except as provided by SR 4.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 and 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

SURVEILLANCE REQUIREMENTS (Continued)

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days.

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - $T_{avg} > 200°F$

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to 1.3% delta k/k.

APPLICABILITY: MODES 1, 2*, 3, and 4.

ACTION:

With the SHUTDOWN MARGIN less than 1.3% delta k/k, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.3% delta k/k:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable control rod(s).

b. When in MODE 1 or MODE 2 with K_{eff} greater than or equal to 1.0, at least once per 12 hours by verifying that control banks are within the limits in the COLR per Specification 3.1.3.5.

c. When in MODE 2 with K_{eff} less than 1.0, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits in the COLR per Specification 3.1.3.5.

*See Special Test Exception 3.10.1

SURVEILLANCE REQUIREMENTS (Continued)

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the control banks at the maximum insertion limit in the COLR per Specification 3.1.3.5.

e. When in MODES 3 or 4, at least once per 24 hours by consideration of the following factors:

1. Reactor coolant system boron concentration,

2. Control rod position,

3. Reactor coolant system average temperature,

4. Fuel burnup based on gross thermal energy generation,

5. Xenon concentration, and

6. Samarium concentration.

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within ± 1% delta k/k at least once per 31 Effective Full Power Days (EFPD). This comparison shall consider at least those factors stated in Specification 4.1.1.1.1.e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

SHUTDOWN MARGIN - T_{avg} ≤ 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to 1.0% delta k/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than 1.0% delta k/k, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.0% delta k/k:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable control rod(s).

b. At least once per 24 hours by consideration of the following factors:

1. Reactor coolant system boron concentration,
2. Control rod position,
3. Reactor coolant system average temperature,
4. Fuel burnup based on gross thermal energy generation,
5. Xenon concentration, and
6. Samarium concentration.

MODERATOR TEMPERATURE COEFFICIENT

LIMITING CONDITION FOR OPERATION

3.1.1.3 The moderator temperature coefficient (MTC) shall be within the limits specified in the CORE OPERATING LIMITS REPORT (COLR). The maximum upper limit shall be less positive than or equal to 0 $\Delta k/k/°F$.

APPLICABILITY: Beginning of Cycle Life (BOL) Limit - MODES 1 and 2* only#
End of Cycle Life (EOL) Limit - MODES 1, 2 and 3 only#

ACTION:

a. With the MTC more positive than the BOL limit specified in the COLR, operations in MODES 1 and 2 may proceed provided:

1. Control rod withdrawal limits are established and maintained sufficient to restore the MTC to less positive than the BOL limit specified in the COLR within 24 hours or be in HOT STANDBY within the next 6 hours. These withdrawal limits shall be in addition to the insertion limits in the COLR per Specification 3.1.3.5.

2. The control rods are maintained within the withdrawal limits established above until a subsequent calculation verifies that the MTC has been restored to within its limit for the all rods withdrawn condition.

3. In lieu of any other report required by Specification 6.9.1, a Special Report is prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days, describing the value of the measured MTC, the interim control rod withdrawal limits and the predicted average core burnup necessary for restoring the positive MTC to within its limit for the all rods withdrawn condition.

b. With the MTC more negative than the EOL limit specified in the COLR, be in HOT SHUTDOWN within 12 hours.

*With K_{eff} greater than or equal to 1.0

#See Special Test Exception 3.10.3

SURVEILLANCE REQUIREMENTS

4.1.1.3 The MTC shall be determined to be within its limits during each fuel cycle as follows:

a. The MTC shall be measured and compared to the BOL limit specified in the COLR prior to initial operation above 5% of RATED THERMAL POWER, after each fuel loading.

b. The MTC shall be measured at any THERMAL POWER and compared to the 300 ppm surveillance limit specified in the COLR (all rods withdrawn, RATED THERMAL POWER condition) within 7 EFPD after reaching an equilibrium boron concentration of 300 ppm. In the event this comparison indicates the MTC is more negative than the 300 ppm surveillance limit specified in the COLR, the MTC shall be remeasured, and compared to the EOL MTC limit specified in the COLR at least once per 14 EFPD during the remainder of the fuel cycle.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.4 The Reactor Coolant System lowest operating loop temperature (T_{avg}) shall be greater than or equal to 541°F.

APPLICABILITY: MODES 1 and 2#*.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{avg}) less than 541°F, restore T_{avg} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.4 The Reactor Coolant System temperature (T_{avg}) shall be determined to be greater than or equal to 541°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{avg} is less than 551°F with the T_{avg} - T_{ref} Deviation Alarm not reset.

#With K_{eff} greater than or equal to 1.0.
*See Special Test Exception 3.10.3.

REACTIVITY CONTROL SYSTEMS

3/4.1.2 BORATION SYSTEMS

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE:

a. A flow path from the boric acid tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System if the boric acid storage system is OPERABLE, per Specification 3.1.2.6a while in MODE 4, or per Specification 3.1.2.5a while in MODE 5 or 6, or

b. ~~A~~ flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System if the refueling water storage tank is OPERABLE per Specification 3.1.2.6b while in MODE 4, or per Specification 3.1.2.5b while in MODE 5 or 6.

APPLICABILITY: MODES 4, 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until at least one injection path is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. When the boric acid tank is a required water source, by verifying at least once per 7 days that:

(1) The flow path from the boric acid tank to the boric acid transfer pump, the boric acid transfer pump, and the recirculation path from the boric acid transfer pump to the boric acid tank is $\geq 63°F$, and

(2) The flow path between the boric acid transfer pump recirculation line to the charging pump suction line is $\geq 50°F$,

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 At least two of the following three boron injection flow paths shall be OPERABLE:

a. A flow path from the boric acid tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System.

b. Two flow paths from the refueling water storage tank via charging pumps to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F within the next 6 hours; restore at least two flow paths to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.2 Each of the above required flow paths shall be demonstrated OPERABLE:

a. By verifying at least once per 7 days that:

(1) The flow path from the boric acid tank to the boric acid transfer pump and from the recirculation line back to the boric acid tank is ≥ 63°F, and

(2) The flow path between the boric acid tank recirculation line to the charging pump suction line is ≥ 50°F,

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. At least once per 18 months during shutdown by verifying that each automatic valve in the flow path actuates to its correct position on a safety injection test signal.

d. At least once per 18 months by verifying that the flow path required by Specification 3.1.2.2.a delivers at least 33 gpm to the Reactor Coolant System.

CHARGING PUMP - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.3 At least one charging pump in the boron injection flow path required by Specification 3.1.2.1 shall be OPERABLE.#

APPLICABILITY: MODES 4, 5 and 6.

ACTION:

With no charging pump OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until one charging pump is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.3 No additional Surveillance Requirements other than those required by Specification 4.0.5.

A maximum of one centrifugal charging pump shall be OPERABLE while in MODE 4 when the temperature of one or more of the RCS cold legs is less than or equal to 312°F, MODE 5, or MODE 6 when the head is on the reactor vessel.

REACTIVITY CONTROL SYSTEMS

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4 No additional Surveillance Requirements other than those required by Specification 4.0.5.

BORATED WATER SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.5 As a minimum, one of the following borated water sources shall be OPERABLE:

a. A boric acid storage system with:

1. A minimum contained volume of 2,600 gallons,
2. Between 6,560 and 6,990 ppm of boron, and
3. A minimum solution temperature of 63°F.

b. The refueling water storage tank with:

1. A minimum contained volume of 37,000 gallons,
2. A minimum boron concentration of 2,300 ppm, and
3. A minimum solution temperature of 35°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes until at least one borated water source is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.5 The above required borated water source shall be demonstrated OPERABLE:

a. For the boric acid storage system, when it is the source of borated water at least once per 7 days by:

1. Verifying the boron concentration of the water,
2. Verifying the water level of the tank, and
3. Verifying the boric acid storage tank solution temperature when it is the source of borated water.

b. For the refueling water storage tank by:

1. Verifying the boron concentration at least once per 7 days,
2. Verifying the borated water volume at least once per 7 days, and
3. Verifying the solution temperature at least once per 24 hours, when it is the source of borated water and the outside air temperature is less than 35°F.

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.6 As a minimum, the following borated water source(s) shall be OPERABLE as required by Specifications 3.1.2.1 and 3.1.2.2:

a. A boric acid storage system with:
   1. A contained volume of borated water in accordance with figure 3.1-2,
   2. A Boron concentration in accordance with Figure 3.1-2, and
   3. A minimum solution temperature of 63°F.

b. The refueling water storage tank with:
   1. A contained volume of between 364,500 and 400,000 gallons of water,
   2. A boron concentration of between 2,300 and 2,500 ppm, and
   3. A minimum solution temperature of 35°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With the boric acid storage system inoperable and being used as one of the above required borated water sources, restore the storage system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F; restore the boric acid storage system to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 Each borated water source shall be demonstrated OPERABLE:

a. For the boric acid storage system, when it is the source of borated water at least once per 7 days by:
   1. Verifying the boron concentration in each water source.
   2. Verifying the water level of each water source, and
   3. Verifying the boric acid storage system solution temperature.

b. For the refueling water storage tank by:
   1. Verifying the boron concentration at least once per 7 days,
   2. Verifying the borated water volume at least once per 7 days, and
   3. Verifying the solution temperature at least once per 24 hour when the outside air temperature is less than 35°F.

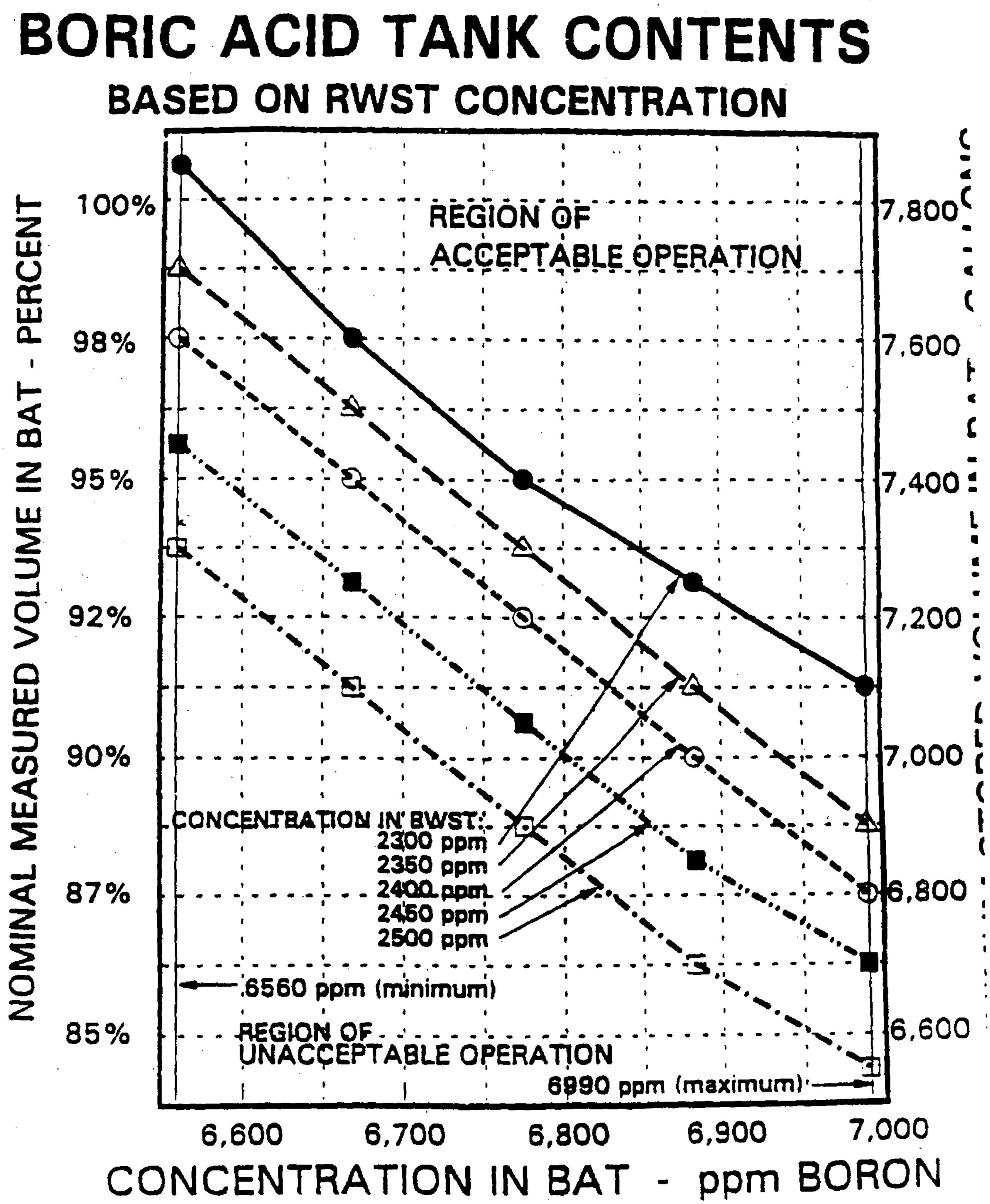
BORIC ACID TANK CONTENTS
BASED ON RWST CONCENTRATION
NOMINAL MEASURED VOLUME IN BAT - PERCENT
100%
98%
95%
92%
90%
87%
85%
7,800
7,600
7,400
7,200
7,000
6,800
6,600
REGION OF
ACCEPTABLE OPERATION
CONCENTRATION IN RWST:
2300 ppm
2350 ppm
2400 ppm
2450 ppm
2500 ppm
6560 ppm (minimum)
REGION OF
UNACCEPTABLE OPERATION
6990 ppm (maximum)
6,600
6,700
6,800
6,900
7,000
CONCENTRATION IN BAT - ppm BORON

Figure 3.1-2

GROUP HEIGHT

LIMITING CONDITION FOR OPERATION

3.1.3.1 All full length (shutdown and control) rods, shall be OPERABLE and positioned within ± 18 steps (indicated position) when reactor power is ≤ 85% RATED THERMAL POWER, or ± 12 steps (indicated position) when reactor power is > 85% RATED THERMAL POWER, of their group step counter demand position within one hour after rod motion.

APPLICABILITY: MODES 1* and 2*

ACTION:

a. With one or more full length rods inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in HOT STANDBY within 6 hours.

b. With more than one full length rod inoperable or mis-aligned from the group step counter demand position by more than ± 18 steps (indicated position) at ≤ 85% RATED THERMAL POWER or ± 12 steps (indicated position) at > 85% RATED THERMAL POWER, be in HOT STANDBY within 6 hours.

c. With one full length rod inoperable due to causes other than addressed by ACTION a, above, or mis-aligned from its group step counter demand position by more than ± 18 steps (indicated position) at ≤ 85% RATED THERMAL POWER or ± 12 steps (indicated position) at > 85% RATED THERMAL POWER, POWER OPERATION may continue provided that within one hour either:

   1. The rod is restored to OPERABLE status within the above alignment requirements, or

   2. The remainder of the rods in the bank with the inoperable rod are aligned to within ± 18 steps (indicated position) at ≤ 85% RATED THERMAL POWER or ± 12 steps (indicated position) at >85% RATED THERMAL POWER, of the inoperable rod while maintaining the rod sequence and insertion limits in the COLR per Specification 3.1.3.5. The THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.5 during subsequent operation, or

   3. The rod is declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. POWER OPERATION may then continue provided that:

*See Special Test Exceptions 3.10.2 and 3.10.3.

a) A reevaluation of each accident analysis of Table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions.

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

c) A core power distribution measurement is obtained and $F_Q(Z)$ and $F^N_{\Delta H}$ are verified to be within their limits within 72 hours.

d) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within one hour and within the next 4 hours the high neutron flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER. THERMAL POWER shall be maintained less than or equal to 75% of RATED THERMAL POWER until compliance with ACTIONS 3.1.3.1.c.3.a and 3.1.3.1.c.3.c above are demonstrated.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full length rod shall be determined to be within the limits established in the limiting condition for operation at least once per 12 hours (allowing for one hour thermal soak after rod motion) except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.

4.1.3.1.2 Each full length rod not fully inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction at least once per 31 days.

TABLE 3.1-1

ACCIDENT ANALYSES REQUIRING REEVALUATION IN THE EVENT OF AN INOPERABLE FULL LENGTH ROD

Rod Cluster Control Assembly Insertion Characteristics

Rod Cluster Control Assembly Mis-alignment

Loss Of Reactor Coolant From Ruptured Pipes Or From Cracks In Large Pipes Which Actuates The Emergency Core Cooling System

Single Rod Cluster Control Assembly Withdrawal At Full Power

Major Reactor Coolant System Pipe Ruptures (Loss Of Coolant Accident)

Major Secondary System Pipe Rupture

Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

POSITION INDICATION SYSTEMS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2.1 The shutdown and control rod position indication systems shall be OPERABLE and capable of determining the actual and demanded rod positions as follows:

a. Analog rod position indicators, within one hour after rod motion (allowance for thermal soak);

All Shutdown Banks: ± 18 steps at ≤85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Bank A: ± 18 steps at ≤85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Bank B: ± 18 steps at ≤85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 160-228 steps.

Control Banks C and D: ± 18 steps at ≤85% reactor power or if reactor power is > 85% RATED THERMAL POWER ± 12 steps of the group demand counters for withdrawal range of 0-228 steps.

b. Group demand counters; ± 2 steps of the pulsed output of the Slave Cycler Circuit over the withdrawal range of 0-228 steps.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With a maximum of one analog rod position indicator per bank inoperable either:

1. Determine the position of the non-indicating rod(s) indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) at least once per 8 hours and within one hour after any motion of the non-indicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

b. With two or more analog rod position indicators per bank inoperable, within one hour restore the inoperable rod position indicator(s) to OPERABLE status or be in HOT STANDBY within the next 6 hours. A maximum of one rod position indicator per bank may remain inoperable following the hour, with Action (a) above being applicable from the original entry time into the LCO.

c. With a maximum of one group demand position indicator per bank inoperable either:

1. Verify that all analog rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 18 steps when reactor power is ≤ 85% RATED THERMAL POWER or if reactor power is > 85% RATED THERMAL POWER, 12 steps of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2.1.1 Each analog rod position indicator shall be determined to be OPERABLE by verifying that the demand position indication system and the rod position indication system agree within 18 steps when reactor power is ≤ 85% RATED THERMAL POWER or if reactor power is > 85% RATED THERMAL POWER, 12 steps (allowing for one hour thermal soak after rod motion) at least once per 12 hours except during time intervals when the Rod Position Deviation Monitor is inoperable, then compare the demand position indication system and the rod position indication system at least once per 4 hours.

4.1.3.2.1.2 Each of the above required rod position indicator(s) shall be determined to be OPERABLE by performance of a CHANNEL calibration at least once per 18 months.

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ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.3 The individual full length (shutdown and control) rod drop time from 228 steps withdrawn shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 541°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 & 2.

ACTION:

a. With the drop time of any full length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

b. With the rod drop times within limits but determined with 3 reactor coolant pumps operating, operation may proceed provided THERMAL POWER is restricted to less than or equal to 76% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.1.3.3 The rod drop time of full length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the control rod drive system which could affect the drop time of those specific rods, and

c. At least once per 18 months.

SHUTDOWN ROD INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.4 All shutdown rods shall be FULLY WITHDRAWN.

APPLICABILITY: MODES 1*, and 2*#@.

ACTION:

With a maximum of one shutdown rod not FULLY WITHDRAWN, except for surveillance testing pursuant to Specification 4.1.3.1.2, within one hour either:

a. FULLY WITHDRAW the rod, or,

b. Declare the rod to be inoperable and apply Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.4 Each shutdown rod shall be determined to be FULLY WITHDRAWN by use of the group demand counters, and verified by the analog rod position indicators**:

a. Within 15 minutes prior to withdrawal of any rods in control banks A, B, C, and D during an approach to reactor critically, and

b. At least once per 12 hours thereafter.

* See Special Test Exceptions 3.10.2 and 3.10.3.

** For power levels below 50% one hour thermal "soak time" is permitted. During this soak time, the absolute value of rod motion is limited to six steps.

@ Surveillance 4.1.3.4.a is applicable prior to withdrawing any control banks in preparation for startup (Mode 2).

\# With Keff greater than or equal to 1.0.

Note: This page effective prior to startup from fifth refueling outage scheduled to begin March 1990. Letter dated Jan. 11, 1990.

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.5 The control banks shall be limited in physical insertion as specified in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODES 1*, and 2*#

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification 4.1.3.1.2, either:

a. Restore the control banks to within the limits within two hours, or

b. Reduce THERMAL POWER within two hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the insertion limits specified in the CLOR, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.5 The position of each control bank shall be determined to be within the insertion limits at least once per 12 hours by use of the group demand counters and verified by the analog rod position indicators** except during time intervals when the Rod Insertion Limit Monitor is inoperable, then verify the individual rod positions at least once per 4 hours**.

* See Special Test Exceptions 3.10.2 and 3.10.3

** For power levels below 50% one hour thermal "soak time" is permitted. During this soak time, the absolute value of rod motion is limited to six steps.

\# With Keff greater than or equal to 1.0

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3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AXIAL FLUX DIFFERENCE (AFD)

LIMITING CONDITION FOR OPERATION

3.2.1 The indicated AXIAL FLUX DIFFERENCE shall be maintained within the target band about the target flux difference as specified in the CORE OPERATING LIMITS REPORT (CORL).

APPLICABILITY: MODE 1 ABOVE 50% RATED THERMAL POWER*

ACTION:

a. With the indicated AXIAL FLUX DIFFERENCE outside of the target band about the target flux difference as specified in the COLR and with THERMAL POWER:

1. Above 90% of RATED THERMAL POWER, within 15 minutes:

   a) Either restore the indicated AFD to within the target band limits, or

   b) Reduce THERMAL POWER to less than 90% of RATED THERMAL POWER.

2. Between 50% and 90% of RATED THERMAL POWER:

   a) POWER OPERATION may continue provided:

      1) The indicated AFD has not been outside of the target band as specified in the COLR for more than 1 hour penalty deviation cumulative during the previous 24 hours, and

      2) The indicated AFD is within the limits as specified in the COLR. Otherwise, reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 30 minutes and reduce the Power Range Neutron Flux-High Trip Setpoints to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

   b) Surveillance testing of the Power Range Neutron Flux Channels may be performed pursuant to Specification 4.3.1.1.1 provided the indicated AFD is maintained within the limits as specified in the COLR. A total of 16 hours operation may be accumulated with the AFD outside of the target band during this testing without penalty deviation.

*See Special Test Exception 3.10.2

LIMITING CONDITION FOR OPERATION (Continued)

b. THERMAL POWER shall not be increased above 90% of RATED THERMAL POWER unless the indicated AFD is within the target band as specified in the COLR and ACTION a. 2. a) 1), above has been satisfied.

c. THERMAL POWER shall not be increased above 50% of RATED THERMAL POWER unless the indicated AFD has not been outside of the target band as specified in the COLR for more than 1 hour penalty deviation cumulative during the previous 24 hours. Power increases above 50% of RATED THERMAL POWER do not require being within the target band provided the accumulative penalty deviation is not violated.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AXIAL FLUX DIFFERENCE shall be determined to be within its limits during POWER OPERATION above 15% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1. At least once per 7 days when the AFD Monitor Alarm is OPERABLE, and

2. At least once per hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status.

b. Monitoring and logging the indicated AXIAL FLUX DIFFERENCE for each OPERABLE excore channel at least once per hour for the first 24 hours and at least once per 30 minutes thereafter, when the AXIAL FLUX DIFFERENCE Monitor Alarm is inoperable. The logged values of the indicated AXIAL FLUX DIFFERENCE shall be assumed to exist during the interval preceding each logging.

4.2.1.2 The indicated AFD shall be considered outside of its target band when at least 2 or more OPERABLE excore channels are indicating the AFD to be outside the target band. Penalty deviation outside of the target band shall be accumulated on a time basis of:

a One minute penalty deviation for each one minute of POWEROPERATION outside of the target band at THERMAL POWER levels equal to or above 50% of RATED THERMAL POWER, and

b. One-half minute penalty deviation for each one minute of POWER OPERATION outside of the target band at THERMAL POWER levels below 50% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.1.3 The target flux difference of each OPERABLE excore channel shall be determined by measurement at least once per 92 Effective Full Power Days. The provisions of Specification 4.0.4 are not applicable.

4.2.1.4 The target flux difference shall be updated at least once per 31 Effective Full Power Days by either determining the target flux difference pursuant to 4.2.1.3 above or by linear interpolation between the most recently measured value and 0% at the end of the cycle life. The provisions of Specification 4.0.4 are not applicable.

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3/4.2.2 HEAT FLUX HOT CHANNEL FACTOR - $F_Q(Z)$

LIMITING CONDITION FOR OPERATION

3.2.2 $F_Q(z) \leq \frac{F_Q^{RTP}}{P} * K(z)$ for $P > 0.5$, and

$F_Q(z) \leq \frac{F_Q^{RTP}}{0.5} * K(z)$ for $P \leq 0.5$, and

Where F_Q^{RTP} = the F_Q limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT (COLR),

$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$, and

$K(z)$ = the normalized $F_Q(z)$ as a function of core height as specified in the COLR.

APPLICABILITY: MODE 1

ACTION:

With $F_Q(Z)$ exceeding its limit:

a. Reduce THERMAL POWER at least 1% for each 1% $F_Q(Z)$ exceeds the limit within 15 minutes and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours; POWER OPERATION may proceed for up to a total of 72 hours; subsequent POWER OPERATION may proceed provided the Overpower delta T Trip Setpoints have been reduced at least 1% for each 1% $F_Q(Z)$ exceeds the limit. The Overpower delta T Trip Setpoint reduction shall be performed with the reactor in at least HOT STANDBY.

b. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER above the reduced limit required by a. above; THERMAL POWER may then be increased provided $F_Q(Z)$ is demonstrated through a core power distribution measurement to be within its limit.

SURVEILLANCE REQUIREMENTS

4.2.2.1 The provisions of Specification 4.0.4 are not applicable.

4.2.2.2 F_{xy} shall be evaluated to determine if $F_Q(Z)$ is within its limit by:

a. Using the movable incore detectors to obtain a power distribution map:

1. When THERMAL POWER is ≤ 25%, but > 5% of RATED THERMAL POWER, or

2. When the Power Distribution Monitoring System (PDMS) is inoperable;

and increasing the Measured $F_Q(Z)$ by the applicable manufacturing and measurement uncertainties as specified in the COLR.

b. Using the PDMS or the moveable incore detectors when THERMAL POWER is > 25% of RATED THERMAL POWER, and increasing the measured $F_Q(Z)$ by the applicable manufacturing and measurement uncertainties as specified in the COLR.

c. Comparing the F_{xy} computed (F_{xy}^C) obtained in b, above to:

1. The F_{xy} limits for RATED THERMAL POWER (F_{xy}^{RTP}) for the appropriate measured core planes given in e. and f., below, and

2. The relationship:

$$F_{xy}^L = F_{xy}^{RTP} \ [1 + PF_{xy}(1-P)]$$

where F_{xy}^L is the limit for fractional THERMAL POWER operation expressed as a function of F_{xy}^{RTP}, PF_{xy} is the power factor multiplier for F_{xy} in the COLR, and P is the fraction of RATED THERMAL POWER at which F_{xy} was measured.

d. Remeasuring F_{xy} according to the following schedule:

1. When F_{xy}^C is greater than the F_{xy}^{RTP} limit for the appropriate measured core plane but less than the F_{xy}^L relationship, additional core power distribution measurements shall be taken and F_{xy}^C compared to F_{xy}^{RTP} and F_{xy}^L:

a) Either within 24 hours after exceeding by 20% of RATED THERMAL POWER or greater, the THERMAL POWER at which F_{xy}^C was last determined, or

b) At least once per 31 EFPD, whichever occurs first.

SURVEILLANCE REQUIREMENTS (Continued)

2. When the F^{C}_{xy} is less than or equal to the F^{RTP}_{xy} limit for the appropriate measured core plane, additional core power distribution measurements shall be taken and F^{C}_{xy} compared to F^{RTP}_{xy} and F^{L}_{xy} at least once per 31 EFPD.

e. The F_{xy} limit for Rated Thermal Power (F^{RTP}_{xy}) shall be provided for all core planes containing bank "D" control rods and all unrodded core planes in the COLR per specification 6.9.1.9.

f. The F_{xy} limits of e., above, are not applicable in the following core plane regions as measured in percent of core height from the bottom of the fuel:

1. Lower core region from 0% to 15%, inclusive.
2. Upper core region from 85% to 100%, inclusive.
3. Grid plane regions at 17.8% ± 2%, 32.1% ± 2%, 46.4% ± 2%, 60.6% ± 2% and 74.9% ± 2%, inclusive.
4. Core plane regions within ± 2% of core height (± 2.88 inches) about the bank demand position of the bank "D" control rods.

g. Evaluating the effects of F_{xy} on $F_Q(Z)$ to determine if $F_Q(Z)$ is within its limit whenever F^{C}_{xy} exceeds F^{L}_{xy}.

4.2.2.3 When $F_Q(Z)$ is measured pursuant to specification 4.10.2.2, an overall measured $F_Q(Z)$ shall be obtained from a core power distribution measurement and increased by the applicable manufacturing and measurement uncertainties* as specified in the COLR.

* For Cycle 11, when the number of available movable detector thimbles is greater than or equal to 50% and less than 75% of the total, the 5% measurement uncertainty shall be increased to [5% + (3-T/14.5)(1%)] where T is the number of available thimbles.

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3/4.2.3 NUCLEAR ENTHALPY HOT CHANNEL FACTOR $F^N_{\Delta H}$

LIMITING CONDITION FOR OPERATION

3.2.3 $F^N_{\Delta H}$ shall be limited by the following relationship:

$$F^N_{\Delta H} = F^{RTP}_{\Delta H} \left[1.0 + PF_{\Delta H} (1.0 - P)\right]$$

Where: $F^{RTP}_{\Delta H}$ is the limit at RATED THERMAL POWER in the Core Operating Limits Report (COLR).

$PF_{\Delta H}$ is the Power Factor Multiplier for $F^N_{\Delta H}$ specified in the COLR, and

P is $\dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

APPLICABILITY: MODE 1

ACTION:

With $F^N_{\Delta H}$ exceeding its limit:

a. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to ≤ 55% of RATED THERMAL POWER within the next 4 hours.

b. Demonstrate through a core power distribution measurement that $F^N_{\Delta H}$ is within its limit within 24 hours after exceeding the limit or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours, and

c. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER above the reduced limit required by a. or b. above; subsequent POWER OPERATION may proceed provided that $F^N_{\Delta H}$ is demonstrated through a core power distribution measurement to be within its limit at a nominal 50% of RATED THERMAL POWER prior to exceeding this THERMAL POWER, at a nominal 75% of RATED THERMAL POWER prior to exceeding this THERMAL POWER and within 24 hours after attaining 95% or greater RATED THERMAL POWER.

4.2.3.1 $F^{N}_{\Delta H}$ shall be determined to be within its limit by obtaining a core power distribution measurement:

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. At least once per 31 Effective Full Power Days.

c. The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 The measured $F^{N}_{\Delta H}$ of 4.2.3.1 above, shall be increased by the applicable $F^{N}_{\Delta H}$ uncertainties* specified in the COLR.

* For Cycle 11, when the number of available movable detector thimbles is greater than or equal to 50% and less than 75% of the total, the 4% measurement uncertainty shall be increased to [4% + (3-T/14.5)(1%)] where T is the number of available thimbles.

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3/4.2.4 QUADRANT POWER TILT RATIO

LIMITING CONDITION FOR OPERATION

3.2.4 The QUADRANT POWER TILT RATIO shall not exceed 1.02.

APPLICABILITY: MODE 1 above 50% of RATED THERMAL POWER*.

ACTION:

a. With the QUADRANT POWER TILT RATIO determined to exceed 1.02 but less than or equal to 1.09:

1. Calculate the QUADRANT POWER TILT RATIO at least once per hour until:

a) Either the QUADRANT POWER TILT RATIO is reduced to within its limit, or

b) THERMAL POWER is reduced to less than 50% of RATED THERMAL POWER.

2. Within 2 hours:

a) Either reduce the QUADRANT POWER TILT RATIO to within its limit, or

b) Reduce THERMAL POWER at least 3% from RATED THERMAL POWER for each 1% of indicated QUADRANT POWER TILT RATIO in excess of 1.0 and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours.

3. a) Verify that the QUADRANT POWER TILT RATIO is within its limit within 24 hours after exceeding the limit or reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within the next 2 hours and reduce the Power Range Neutron Flux-High Trip setpoints to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

*See Special Test Exception 3.10.2.

b) Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL power may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified acceptable at 95% or greater RATED THERMAL POWER.

b. With the QUADRANT POWER TILT RATIO determined to exceed 1.09 due to misalignment of either a shutdown or control rod:

1. Calculate the QUADRANT POWER TILT RATIO at least once per hour until:

   (a) Either the QUADRANT POWER TILT RATIO is reduced to within its limit, or

   (b) THERMAL POWER is reduced to less than 50% of RATED THERMAL POWER.

2. Reduce THERMAL POWER at least 3% from RATED THERMAL POWER for each 1% of indicated QUADRANT POWER TILT RATIO in excess of 1.0, within 30 minutes.

3. Verify that the QUADRANT POWER TILT RATIO is within its limit within 2 hours after exceeding the limit or reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within the next 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

4. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL POWER may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified acceptable at 95% or greater RATED THERMAL POWER.

c. With the QUADRANT POWER TILT RATIO determined to exceed 1.09 due to causes other than the misalignment of either a shutdown or control rod:

LIMITING CONDITION FOR OPERATION (Continued)

1. Calculate the QUADRANT POWER TILT RATIO at least once per hour until:

   (a) Either the QUADRANT POWER TILT RATIO is reduced to within its limit, or

   (b) THERMAL POWER is reduced to less than 50% of RATED THERMAL POWER.

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

3. Identify and correct the cause of the out of limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL POWER may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified at 95% or greater RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.4.1 The QUADRANT POWER TILT RATIO shall be determined to be within the limit above 50% of RATED THERMAL POWER by:

a. Calculating the ratio at least once per 7 days when the alarm is OPERABLE.

b. Calculating the ratio at least once per 12 hours during steady-state operation when the alarm is inoperable.

4.2.4.2 The QUADRANT POWER TILT RATIO shall be determined to be within the limit when above 75% of RATED THERMAL POWER with one Power Range Channel inoperable by obtaining a core power distribution measurement* to confirm that the normalized symmetric power distribution is consistent with the indicated QUADRANT POWER TILT RATIO at least once per 12 hours.

* Using either the movable incore detectors in the four pairs of symmetric thimble locations or the power distribution monitoring system.

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the limits shown on Table 3.2-1:

a. Reactor Coolant System T_{avg}.

b. Pressurizer Pressure.

c. Reactor Coolant System Total Flow Rate.

APPLICABILITY: MODE 1

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters of Table 3.2-1 shall be verified to be within their limits at least once per 12 hours.

4.2.5.2 The Reactor Coolant System Total Flow Rate shall be determined to be within the limits of Table 3.2-1 by performing a precision heat balance within 24 hours after achieving steady state conditions ≥90% RATED THERMAL POWER at least once per 18 months. The provisions of Specification 4.0.4 are not applicable.

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS 4 Loops in Operation
Reactor Coolant System T_{avg}	≤ 582.9°F
Pressurizer Pressure	≥ 2200 psia*
Reactor Coolant System Total Flow Rate	≥ 341,000 gpm#

* Limit not applicable during either a THERMAL POWER ramp in excess of 5% RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% RATED THERMAL POWER.

Includes a 2.4% flow uncertainty plus a 0.1% measurement uncertainty due to feedwater venturi fouling.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1.1 As a minimum, the reactor trip system instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each reactor trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.3-1.

4.3.1.1.2 The logic for the interlocks shall be demonstrated OPERABLE prior to each reactor startup unless performed during the preceding 92 days. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.1.1.3 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be verified to be within its limit at least once per 18 months. Neutron detectors are exempt from response time testing. Each verification shall include at least one logic train such that both logic trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. of Channels" column of Table 3.3-1.

TABLE 3.3-1
REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1,2 and *	12
2. Power Range, Neutron Flux	4	2	3	1,2 and 3*	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1,2	2
4. Deleted					
5. Intermediate Range, Neutron Flux	2	1	2	1,2 and *	3
6. Source Range, Neutron Flux					
A. Startup	2	1	2	2##, and *	4
B. Shutdown	2	0	1	3,4 and 5	5
7. Overtemperature ΔT	4	2	3	1,2	6
8. Overpower ΔT	4	2	3	1,2	6
9. Pressurizer Pressure-Low	4	2	3	1,2	6
10. Pressurizer Pressure--High	4	2	3	1,2	6

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS ACTION	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	
11. Pressurizer Water Level--High	3	2	2	1, 2	6
12. Loss of Flow - Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	6
13. Loss of Flow - Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop in each operating loop	1	6
14. Steam Generator Water Level--Low-Low	3/loop	2/loop in any operating loops	2/loop in each operating loop	1, 2	6
15. Deleted					
16. Undevoltage-Reactor Coolant Pumps	4-1/bus	1/2 twice	3	1	6
17. Underfrequency-Reactor Coolant Pumps	4-1/bus	1/2 twice	3	1	6

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
a. Low Autostop Oil Pressure	3	2	2	1	6
b. Turbine Stop Valve Closure	4	4	3	1	6
19. Safety Injection Input from ESF	2	1	2	1,2	10
20. Reactor Coolant Pump Breaker Position Trip (above P-7)	1/breaker	2	1/breaker per operating loop	1	11
21. Reactor Trip Breakers	2	1	2	1,2 3*,4*,5*	1###, 14 13
22. Automatic Trip Logic	2	1	2	1,2 3*,4*,5*	10 13

TABLE 3.3-1 (Continued)

TABLE NOTATION

* With the reactor trip system breakers in the closed position and the control rod drive system capable of rod withdrawal.

High voltage to detector may be de-energized above P-6.

If ACTION Statement 1 is entered as a result of Reactor Trip Breaker (RTB) or Reactor Trip Bypass Breaker (RTBB) maintenance testing results exceeding the following acceptance criteria, NRC reporting shall be made within 30 days in accordance with Specification 6.9.2:

1. A RTB or RTBB trip failure during any surveillance test with less than or equal to 300 grams of weight added to the breaker trip bar.
2. A RTB or RTBB time response failure that results in the overall reactor trip system time response exceeding the Technical Specification limit.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, be in HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1.1 provided the other channel is OPERABLE.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

c. Either, THERMAL POWER is restricted to ≤ 75% of RATED THERMAL POWER and the Power Range, Neutron Flux trip setpoint is reduced to ≤ 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours.

d. The QUADRANT POWER TILT RATIO, as indicated by the remaining three detectors, is verified consistent with the normalized symmetric power distribution obtained by using either the movable in-core detectors in the four pairs of symmetric thimble locations or the power distribution monitoring system at least once per 12 hours when THERMAL POWER is greater than 75% of RATED THERMAL POWER.

TABLE 3.3-1 (Continued)

ACTION 3 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below P-6, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above P-6, but below 5% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 5% of RATED THERMAL POWER.

c. Above 5% of RATED THERMAL POWER, POWER OPERATION may continue.

d. Above 10% of RATED THERMAL POWER, the provisions of Specification 3.0.3 are not applicable.

ACTION 4 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below P-6, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above P-6, operation may continue.

ACTION 5 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channel OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

ACTION 7 - NOT USED

ACTION 8 - NOT USED

ACTION 9 - NOT USED

TABLE 3.3-1 (Continued)

ACTION 10 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY in the next 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1.1 provided the other channel is OPERABLE.

ACTION 11 - With less than the Minimum Number of Channels OPERABLE, operation may continue provided the inoperable channel is placed in the tripped condition within 6 hours.

ACTION 12 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and/or open the reactor trip breakers.

ACTION 13 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

ACTION 14 - With one of the diverse trip features (Undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and be in at least HOT STANDBY within 6 hours. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status.

REACTOR TRIP SYSTEM INTERLOCKS

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-6	With 2 of 2 Intermediate Range Neutron Flux Channels < $6x10^{-11}$ amps.	P-6 prevents or defeats the manual block of source range reactor trip.
P-7	With 2 of 4 Power Range Neutron Flux Channels ≥ 11% of RATED THERMAL POWER or 1 of 2 Turbine steam line inlet pressure channels ≥ a pressure equivalent to 11% of RATED THERMAL POWER.	P-7 prevents or defeats the automatic block of reactor trip on: Low flow in more than one primary coolant loop, reactor coolant pump undervoltage and under-frequency, pressurizer low pressure, pressurizer high level, and the opening of more than one reactor coolant pump breaker.

TABLE 3.3-1 (Continued)

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-8	With 2 of 4 Power Range Neutron Flux channels ≥ 36% of RATED THERMAL POWER.	P-8 prevents or defeats the automatic block of reactor trip on low coolant flow in a single loop.
P-9	With 2 of 4 Power range neutron flux channels ≥ 50% of RATED THERMAL POWER.	P-9 prevents or defeats the automatic block of reactor trip on turbine trip.
P-10	With 3 of 4 Power range neutron flux channels < 9% of RATED THERMAL POWER.	P-10 prevents or defeats the manual block of: Power range low setpoint reactor trip, Intermediate range reactor trip, and intermediate range rod stops. Provides input to P-7.

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TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. Manual Reactor Trip Switch	N.A.	N.A.	$R^{(9)}$	1, 2, and *
2. Power Range, Neutron Flux	S	$D^{(2)}$, $M^{(3)}$ and $Q^{(6)}$	Q	1, 2, and 3*
3. Power Range, Neutron Flux, High Positive Rate	N.A.	$R^{(6)}$	Q	1, 2
4. Deleted				
5. Intermediate Range, Neutron Flux	S	$R^{(6)}$	$S/U^{(1)}$	1, 2 and *
6. Source Range, Neutron Flux	$S^{(7)}$	$R^{(6)}$	Q and $S/U^{(1)}$	2, 3, 4, 5 and *
7. Overtemperature ΔT	S	R	Q	1, 2
8. Overpower ΔT	S	R	Q	1, 2
9. Pressurizer Pressure--Low	S	R	Q	1, 2
10. Pressurizer Pressure--High	S	R	Q	1, 2
11. Pressurizer Water Level--High	S	R	Q	1, 2
12. Loss of Flow - Single Loop	S	R	Q	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
13. Loss of Flow Two Loops	S	R	N.A.	1
14. Steam Generator Water Level--Low-Low	S	R	Q	1, 2
15. DELETED				
16. Undervoltage - Reactor Coolant Pumps	N.A.	R	Q	1
17. Underfrequency - Reactor Coolant Pumps	N.A.	R	Q	1
18. Turbine Trip				
a. Low Autostop Oil Pressure	N.A.	N.A.	S/U(1)	1, 2
b. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1, 2
19. Safety Injection Input from ESF	N.A.	N.A.	M(4)(5)	1, 2
20. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	R	1
21. Reactor Trip Breaker	N.A.	N.A.	M(5)(11)(13) and R(14)	1, 2 and *
22. Automatic Trip Logic	N.A.	N.A.	M(5)	1, 2 and *

TABLE 4.3-1 (Continued)

NOTATION

*		With the reactor trip system breakers closed and the control rod drive system capable of rod withdrawal.
(1)	-	If not performed in previous 31 days.
(2)	-	Heat balance only, above 15% of RATED THERMAL POWER.
(3)	-	Compare incore to excore axial offset above 15% of RATED THERMAL POWER. Recalibrate if absolute difference ≥ 3 percent.
(4)	-	Manual SSPS functional input check every 18 months.
(5)	-	Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS.
(6)	-	Neutron detectors may be excluded from CHANNEL CALIBRATION.
(7)	-	Below P-6 (Block of Source Range Reactor Trip) setpoint.
(8)	-	Deleted
(9)	-	The CHANNEL FUNCTIONAL TEST shall independently verify the OPERABILITY of the Undervoltage and Shunt Trip mechanism for the Manual Reactor Trip Function. The Test shall also verify OPERABILITY of the Bypass Breaker Trip circuits.
(10)	-	DELETED
(11)	-	The CHANNEL FUNCTIONAL TEST shall independently verify the OPERABILITY of the Reactor Trip Breaker Undervoltage and Shunt Trip mechanisms.
(12)	-	DELETED

TABLE 4.3-1 (Continued)

NOTATION

(13) - Verify operation of Bypass Breakers Shunt Trip function from local pushbutton while breaker is in the test position prior to placing breaker in service.

(14) - Perform a functional test of the Bypass Breakers U.V. Attachment via the SSPS.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2.1 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an ESFAS instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint value.

b. With an ESFAS instrumentation channel inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each ESFAS instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations for the MODES and at frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the interlocks shall be demonstrated OPERABLE during the automatic actuation logic test. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be verified to be within the limit at least once per 18 months. Each verification shall include at least one logic train such that both logic trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" Column of Table 3.3-3. The provisions of Specification 4.0.4 are not applicable to MSIV closure time testing. The provisions of Specification 4.0.4 are not applicable to the turbine driven auxiliary feedwater pump provided the surveillance is performed within 24 hours after the secondary steam generator pressure is greater than 680 psig.

TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION					
a. Manual Initiation	2	1	2	1,2,3,4	18
b. Automatic Actuation Logic	2	1	2	1,2,3,4	13
c. Containment Pressure-High	3	2	2	1,2,3	19
d. Pressurizer Pressure-Low	3	2	2	1,2,3#	19
e. Differential Pressure Between Steam Lines - High	3/steam line	2/steam line any steam lines	2/steam line	1,2,3##	19
f. Steam Flow in Two Steam Lines-High	2/steam line	1/steam line any 2 steam lines	1/steam line	1,2,3##	19
COINCIDENT WITH EITHER					
T_{avg} --Low-Low	1 T_{avg}/loop	1 T_{avg} in any 2 loops	1 T_{avg} in any 3 loops	1,2,3##	19
OR, COINCIDENT WITH					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any 2 loops	1 pressure any 3 loops	1,2,3##	19

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TABLE 3.3-3 (Continued)
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
2. CONTAINMENT SPRAY					
a. Manual	2 sets of 2	1 set of 2	2 sets of 2	1,2,3,4	18
b. Automatic Actuation Logic	2	1	2	1,2,3,4	13
c. Containment Pressure--High-High	4	2	3	1,2,3	16
3. CONTAINMENT ISOLATION					
a. Phase "A" Isolation					
1) Manual	2	1	2	1,2,3,4	18
2) From Safety Injection Automatic Actuation Logic	2	1	2	1,2,3,4	13

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
b. Phase "B" Isolation					
1) Manual	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	18
2) Automatic Actuation Logic	2	1	2	1, 2, 3, 4	13
3) Containment Pressure--High-High	4	2	3	1, 2, 3	16
c. Containment Ventilation Isolation					
1) Manual	2	1	2	1, 2, 3, 4	17
2) Automatic Actuation Logic	2	1	2	1, 2, 3, 4	13
3) Containment Atmosphere Gaseous Radioactivity-High		per table 3.3-6			

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. STEAM LINE ISOLATION					
a. Manual	2/steam line	1/steam line	1/operating steam line	1,2,3	23
b. Automatic Actuation Logic	2***	1	2	1,2,3	20
c. Containment Pressure--High-High	4	2	3	1,2,3	16
d. Steam Flow in Two Steam Lines--High	2/steam line	1/steam line any 2 steam lines	1/steam line	1,2,3##	19
COINCIDENT WITH EITHER					
T_{avg}--Low-Low	1 T_{avg}/loop	1 T_{avg} in any 2 loops	1 T_{avg} in any 3 loops	1,2,3##	19
OR, COINCIDENT WITH					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any 2 loops	1 pressure any 3 loops	1,2,3##	19

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
5. TURBINE TRIP @ FEEDWATER ISOLATION					
a. Steam Generator Water level--High-High	3/loop	2/loop in any operating loop	2/loop in each operating loop	1,2,3	19
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC)	3	2	3	1,2,3,4	13
7. UNDERVOLTAGE, VITAL BUS					
a. Loss of Voltage	1/bus	2	3	1,2,3	14
b. Sustained Degraded Voltage	3/bus	2/bus	3/bus	1,2,3	14

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
8. AUXILIARY FEEDWATER					
a. Automatic Actuation Logic **	2	1	2	1,2,3	20
b. NOT USED					
c. Stm. Gen. Water Level-Low-Low					
i. Start Motor Driven Pumps	3/stm. gen.	2/stm. gen. any stm. gen.	2/stm. gen.	1,2,3	19
ii. Start Turbine Driven Pumps	3/stm. gen.	2/stm. gen. any 2 stm.gen.	2/stm. gen.	1,2,3	19
d. Undervoltage - RCP Start Turbine - Driven Pump	4-1/bus	1/2 x 2	3	1,2	19
e. S.I. Start Motor-Driven Pumps	See 1 above (All S.I. initiating functions and requirements)				
f. Trip of Main Feedwater Pumps Start Motor-Driven Pumps	2/pump	1/pump	1/pump	1,2	21
g. Station Blackout	See 6 and 7 above (SEC and UV Vital Bus)				
9. SEMIAUTOMATIC TRANSFER TO RECIRCULATION					
a. RWST Level Low	4	2	3	1,2,3	16
b. Automatic Actuation Logic	2	1	2	1,2,3	20

TABLE 3.3-3 (Continued)

TABLE NOTATION

#	Trip function may be bypassed in this MODE below P-11.
##	Trip function may be bypassed in this MODE below P-12.
**	Applies to Functional Unit 8 items c and d.
***	The automatic actuation logic includes two redundant solenoid operated vent valves for each Main Steam Isolation Valve. One vent valve on any one Main Steam Isolation Valve may be isolated without affecting the function of the automatic actuation logic provided the remaining seven solenoid vent valves remain OPERABLE. The isolated MSIV vent valve shall be returned to OPERABLE status upon the first entry into MODE 5 following determination that the vent valve is inoperable. For any condition where more than one of the eight solenoid vent valves are inoperable, entry into ACTION 20 is required.

ACTION STATEMENTS

ACTION 13 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 6 hours or, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1 provided the other channel is OPERABLE.

ACTION 14 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed until performance of the next required CHANNEL FUNCTIONAL TEST, provided the inoperable channel is placed in the tripped condition within 1 hour.

ACTION 15 - NOT USED

ACTION 16 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is demonstrated by CHANNEL CHECK within 6 hours; one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1.

ACTION 17 - With less than the Minimum Channels OPERABLE, operation may continue provided the containment purge and exhaust valves are maintained closed.

ACTION 18 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.3-3 (Continued)

ACTION 19 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirements is met; However, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.2.1.1.

ACTION 20 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to operable status within 6 hours or, be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1 provided the other channel in OPERABLE.

ACTION 21 - With the number of OPERABLE channels one less than the Minimum Number of Channels, operation may proceed provided that the inoperable channel is restored to OPERABLE within 72 hours.

ACTION 22 - NOT USED

ACTION 23 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES INTERLOCKS

DESIGNATION	CONDITION AND SETPOINT	FUNCTION
P-11	With 2 of 3 pressurizer pressure channels ≥ 1925 psig.	P-11 prevents or defeats manual block of safety injection actuation on low pressurizer pressure.
P-12	With 3 of 4 T_{avg} channels at a setpoint of 543°F and T_{avg} increasing (with an allowable setpoint value ≤545°F)	P-12 prevents or defeats manual block of safety injection actuation high steam line flow and low steam line pressure.
	With 2 of 4 T_{avg} channels at a setpoint of 543°F and T_{avg} decreasing (with an allowable setpoint value ≥541°F)	Allows manual block of safety injection actuation on high steam line flow and low steam line pressure. Causes steam line isolation on high steam flow. Affects steam dump blocks.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High	≤ 4.0 psig	≤ 4.5 psig
d. Pressurizer Pressure--Low	≥ 1765 psig	≥ 1755 psig
e. Differential Pressure Between Steam Lines--High	≤ 100 psi	≤ 112 psi
f. Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low or Steam Line Pressure--Low	≤ A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load T_{avg} ≥ 543°F ≥ 600 psig steam line pressure	≤ A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load T_{avg} ≥ 541°F ≥ 579 psig steam line pressure

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. CONTAINMENT SPRAY		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
3. CONTAINMENT ISOLATION		
a. Phase "A" Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable	Not Applicable
b. Phase "B" Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable
3. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
c. Containment Ventilation Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Atmosphere Gaseous Radioactivity	Per Table 3.3-6	
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	≤ 15.0 psig	≤ 16.0 psig
d. Steam Flow in Two Steam Lines--High Coincident with Tavg -- Low-Low or Steam Line Pressure -- Low	≤ A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load.	≤ A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load.
	T avg ≥ 543°F ≥ 600 psig steam line pressure	T avg ≥ 541°F ≥ 579 psig steam line pressure
5. TURBINE TRIP AND FEEDWATER ISOLATION		
a. Steam Generator Water Level -- High-High	≤ 67% of narrow range instrument span each steam generator	≤ 68% of narrow range instrument span each steam generator
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC)	Not Applicable	Not Applicable

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
TRIP SETPOINTS

FUNCTIONAL UNIT		TRIP SETPOINT	ALLOWABLE VALUES
7.	UNDERVOLTAGE, VITAL BUS		
a.	Loss of Voltage	≥ 70% of bus voltage	≥ 65% of bus voltage
b.	Sustained Degraded Voltage	≥ 94.6% of bus voltage for ≤13 seconds	≥ 94% of bus voltage for ≤ 15 seconds
8.	AUXILIARY FEEDWATER		
a.	Automatic Actuation Logic	Not Applicable	Not Applicable
b.	NOT USED		
c.	Steam Generator Water Level--Low-Low	≥ 14.0% of narrow range instrument span each steam generator	≥ 13.0% of narrow range instrument span each steam generator
d.	Undervoltage - RCP	≥ 70% RCP bus voltage	≥ 65% RCP bus voltage
e.	S.I.	See 1 above (all S.I. setpoints)	
f.	Trip of Main Feedwater Pump	Not Applicable	Not Applicable
g.	Station Blackout	See 6 and 7 above (SEC and Undervoltage, Vital Bus)	
9.	SEMIAUTOMATIC TRANSFER TO RECIRCULATION		
a.	RWST Low Level	15.25 ft. above Instrument taps	15.25 ± 1 ft. above instrument taps
b.	Automatic Actuation Logic	Not Applicable	Not Applicable

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TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION				
a. Manual Initiation	N.A.	N.A.	R	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure--High	S	R	Q(3)	1,2,3
d. Pressurizer Pressure--Low	S	R	Q	1,2,3
e. Differential Pressure Between Steam Lines--High	S	R	Q	1,2,3
f. Steam Flow in Two Steam Lines--High Coincident with Tavg--Low-Low or Steam Line Pressure--Low	S	R	Q	1,2,3
2. CONTAINMENT SPRAY				
a. Manual Initiation	N.A.	N.A.	R	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure--High-High	S	R	Q(3)	1,2,3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
3. CONTAINMENT ISOLATION				
a. Phase "A" Isolation				
1) Manual	N.A.	N.A.	R	1,2,3,4
2) From Safety Injection Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
b. Phase "B" Isolation				
1) Manual	N.A.	N.A.	R	1,2,3,4
2) Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
3) Containment Pressure--High-High	S	R	Q(3)	1,2,3
c. Containment Ventilation Isolation				
1) Manual	N.A.	N.A.	R	1,2,3,4
2) Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
3) Containment Atmosphere Gaseous Radioactivity-High		Per table 4.3-3		

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4. STEAM LINE ISOLATION				
a. Manual	N.A.	N.A.	R	1,2,3**
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3
c. Containment Pressure--High-High	S	R	Q(3)	1,2,3
d. Steam Flow in Two Steam Lines--High Coincident with Tavg--Low-Low or Steam Line Pressure--Low	S	R	Q	1,2,3
5. TURBINE TRIP AND FEEDWATER ISOLATION				
a. Steam Generator Water Level--High-High	S	R	Q	1,2,3
6. SAFEGUARDS EQUIPMENT CONTROL SYSTEM (SEC) LOGIC				
a. Inputs	N.A.	N.A.	M(6)	1,2,3,4
b. Logic, Timing and Outputs *	N.A.	N.A.	M(1)	1,2,3,4
7. UNDERVOLTAGE, VITAL BUS				
a. Loss of Voltage	S	R	M	1,2,3
b. Sustained Degraded Voltage	S	R	M	1,2,3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
8. AUXILIARY FEEDWATER				
a. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3
b. NOT USED				
c. Steam Generator Water Level--Low-Low	S	R	Q	1,2,3
d. Undervoltage - RCP	S	R	Q	1,2
e. S.I.	See 1 above (All S.I. surveillance requirements)			
f. Trip of Main Feedwater Pumps	N.A.	N.A.	S/U(4)	1,2
g. Station Blackout	See 6 and 7 above (SEC and U/V Vital Bus)			
9. SEMIAUTOMATIC TRANSFER TO RECIRCULATION				
a. RWST Low Level	S	R	Q	1,2,3
b. Automatic Initiation Logic	N.A.	N.A.	M(2)	1,2,3,4

TABLE 4.3-2 (Continued)

TABLE NOTATION

* Outputs are up to, but not including, the Output Relays.

** The provisions of Specification of 4.0.4 are not applicable.

(1) Each logic channel shall be tested at least once per 62 days on a STAGGERED TEST BASIS. The CHANNEL FUNCTION TEST of each logic channel shall verify that its associated diesel generator automatic load sequence timer is OPERABLE with the interval between each load block within 1 second of its design interval.

(2) Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(3) The CHANNEL FUNCTIONAL TEST shall include exercising the transmitter by applying either a vacuum or pressure to the appropriate side of the transmitter.

(4) If not performed in the previous 92 days.

(5) NOT USED

(6) Inputs from undervoltage, Vital Bus, shall be tested monthly. Inputs from Solid State Protection System, shall be tested every 62 days on a STAGGERED TEST BASIS.

INSTRUMENTATION

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels shown in Table 3.3-6 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel alarm/trip setpoint exceeding the value shown in Table 3.3-6, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION shown in Table 3.3-6.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-3.

TABLE 3.3-6
RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. AREA MONITORS					
a. Fuel Storage Area	1	*	≤15 mR/hr	10^{-1}-10^{4} mR/hr	23
2. PROCESS MONITORS					
a. Containment					
1) Gaseous Activity					
a) Purge & Pressure Vacuum Relief Isolation	1#	1,2,3,4&5	per ODCM Control 3.3.3.9	10^{1}-10^{6} cpm	26
b) RCS Leakage Detection	1	1,2,3&4	N/A	10^{1}-10^{6} cpm	24
2) Air Particulate Activity					
a) (NOT USED)					
b) RCS Leakage Detection	1	1,2,3&4	N/A	10^{1}-10^{6} cpm	24

* With fuel in the storage pool or building.

\# The plant vent noble gas monitor may also function in this capacity when the purge/pressure-vacuum relief isolation valves are open.

TABLE 3.3-6 (Continued)
RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
2. PROCESS MONITORS					
b. Noble Gas Effluent Monitors					
1) Medium Range Auxiliary Building Exhaust System (Plant Vent)	1	1,2,3&4	$\leq 3.0 \times 10^{-2}$ µCi/cm^3 (Alarm only)	10^{-3}-10^{1} µCi/cm^3	26
2) High Range Auxiliary Building Exhaust System (Plant Vent)	1	1,2,3&4	$\leq 1.0 \times 10^{2}$ µCi/cm^3 (Alarm only)	10^{-1}-10^{5} µCi/cm^3	26
3) Condenser Exhaust System	1	1,2,3&4	$\leq 7.12 \times 10^{4}$ cpm (Alarm only)	1-10^{6} cpm	26
3. CONTROL ROOM					
a. Air Intake - Radiation Level	2/Intake##	**	$\leq 2.48 \times 10^{3}$ cpm	10^{1}-10^{7} cpm	27,28

Control Room air intakes shared between Unit 1 and 2.

** ALL MODES and during movement of irradiated fuel assemblies and during CORE ALTERATIONS.

TABLE 3.3-6 (Continued)

TABLE NOTATION

ACTION 23 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 24 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.7.1.

ACTION 25 - (Not Used)

ACTION 26 - With the number of OPERABLE Channels less than required by the Minimum Channels OPERABLE requirements, initiate the preplanned alternate method of monitoring the appropriate parameter(s), within 72 hours, and:

1) either restore the inoperable Channel(s) to OPERABLE status within 7 days of the event, or

2) prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 27 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel(s) to OPERABLE status within 7 days or initiate and maintain operation of the Control Room Emergency Air Conditioning System (CREACS) in the pressurization or recirculation mode of operation. CORE ALTERATIONS and movement of irradiated fuel assemblies will be suspended during operation in the recirculation mode.

ACTION 28 - With no channels OPERABLE in a Control Room air intake, immediately initiate and maintain operation of the CREACS in the pressurization or recirculation mode of operation. CORE ALTERATIONS and movement of irradiated fuel assemblies will be suspended during operation in the recirculation mode.

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TABLE 4.3-3
RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNELS CHECKS	SOURCE CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. AREA MONITORS					
a. Fuel Storage Area	S	M	R	Q	*
2. PROCESS MONITORS					
a. Containment Monitors					
1) Gaseous Activity					
a) Purge & Pressure Vacuum Relief Isolation	S	M	R	Q	1, 2, 3, 4 & 5
b) RCS Leakage Detection	S	M	R	Q	1, 2, 3 & 4
2) Air Particulate Activity					
a) (NOT USED)					
b) RCS Leakage Detection	S	M	R	Q	1, 2, 3 & 4

*With fuel in the storage pool or building.

TABLE 4.3-3 (Continued)
RADIATION MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNELS CHECKS	SOURCE CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
2. PROCESS MONITORS					
b. Noble Gas Effluent Monitors					
1) Medium Range Auxiliary Building Exhaust System (Plant Vent)	S	M	R	Q	1, 2, 3 & 4
2) High Range Auxiliary Building Exhaust System (Plant Vent)	S	M	R	Q	1, 2, 3 & 4
3) Main Steamline Discharge (Safety Valves and Atmospheric Dumps)	S	M	R	Q	1, 2, 3 & 4
4) Condenser Exh. Sys.	S	M	R	Q	1, 2, 3 & 4
3. CONTROL ROOM					
a. Air Intake - Radiation Level	S	M	R	Q	**

** ALL MODES and during movement of irradiated fuel assemblies and during CORE ALTERATIONS.

INSTRUMENTATION

REMOTE SHUTDOWN INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.5 The remote shutdown monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE with readouts displayed external to the control room.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring channels less than required by Table 3.3-9, restore the inoperable channel to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.5 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Pressurizer Pressure	Hot Shutdown Panel 213	1700-2500 psig	1
2. Pressurizer Level	Hot Shutdown Panel 213	0 - 100%	1
3. Steam Generator Pressure	Hot Shutdown Panel 213	0 - 1200 psig	1/steam generator
4. Steam Generator Level	Hot Shutdown Panel 213	0 - 100%	1/steam generator

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Pressurizer Pressure	M	R
2. Pressurizer Level	M	R
3. Steam Generator Pressure	M	R
4. Steam Generator Level	M	R

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INSTRUMENTATION

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.7 The accident monitoring instrumentation channels shown in Table 3.3-11 shall be operable.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. As shown in Table 3.3-11.

SURVEILLANCE REQUIREMENTS

4.3.3.7 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3-11.

TABLE 3.3-11

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NO. OF CHANNELS	MINIMUM NO. OF CHANNELS	ACTION
1. Reactor Coolant Outlet Temperature - T_{HOT} (Wide Range)	2	1	1, 2
2. Reactor Coolant Inlet Temperature - T_{COLD} (Wide Range)	2	1	1, 2
3. Reactor Coolant Pressure (Wide Range)	2	1	1, 2
4. Pressurizer Water Level	2	1	1, 2
5. Steam Line Pressure	2/Steam Generator	1/Steam Generator	1, 2
6. Steam Generator Water Level (Narrow Range)	2/Steam Generator	1/Steam Generator	1, 2
7. Steam Generator Water Level (Wide Range)	4(1/Steam Generator)	3 (1/Steam Generator)	1, 2
8. Refueling Water Storage Tank Water Level	2	1	1, 2
9. deleted			
10. Auxiliary Feedwater Flow Rate	4 (1/Steam Generator)	3 (1/Steam Generator)	4, 6
11. Reactor Coolant System Subcooling Margin Monitor	2	1	1, 2
12. PORV Position Indicator	2/valve**	1	1, 2

TABLE 3.3-11 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NO. OF CHANNELS	MINIMUM NO. OF CHANNELS	ACTION
13. PORV Block Valve Position Indicator	2/valve**	1	1, 2
14. Pressurizer Safety Valve Position Indicator	2/valve**	1	1, 2
15. Containment Pressure - Narrow Range	2	1	1, 2
16. Containment Pressure - Wide Range	2	1	7, 2
17. Containment Water Level - Wide Range	2	1	7, 2
18. Core Exit Thermocouples	4/core quadrant	2/core quadrant	1, 2
19. Reactor Vessel Level Instrumentation System (RVLIS)	2	1	8, 9
20. Containment High Range Accident Radiation Monitor	2	2	10
21. Main Steamline Discharge (Safety Valves and Atmospheric Steam Dumps) Monitor	1/ MS Line	1/ MS Line	10

(**) Total number of channels is considered to be two (2) with one (1) of the channels being any one (1) of the following alternate means of determining PORV, PORV Block, or Safety Valve position: Tailpipe Temperatures for the valves, Pressurizer Relief Tank Temperature Pressurizer Relief Tank Level OPERABLE.

TABLE 3.3-11 (continued)

TABLE NOTATION

ACTION 1 With the number of OPERABLE accident monitoring channels less than the Required Number of Channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

ACTION 2 With the number of OPERABLE accident monitoring channels less than the Minimum Number of Channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in HOT SHUTDOWN within the next 12 hours.

ACTION 3 deleted

ACTION 4 With the number of OPERABLE channels one less than the Required Number of Channels shown in Table 3.3-11, operations may proceed provided that an OPERABLE Steam Generator Wide Range Level channel is available as an alternate means of indication for the Steam Generator with no OPERABLE Auxiliary Feedwater Flow Rate Channel.

ACTION 5 deleted

TABLE 3.3-11 (continued)

TABLE NOTATION

ACTION 6 With the number of OPERABLE channels less than the Minimum Number of channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

ACTION 7 With the number of OPERABLE channels one less than the Required Number of Channels shown in Table 3.3-11, operation may proceed until the next CHANNEL CALIBRATION (which shall be performed upon the next entry into MODE 5, COLD SHUTDOWN).

ACTION 8 With one RVLIS channel inoperable, restore the RVLIS channel to OPERABLE status within 30 days, or submit a special report in accordance with Specification 6.9.4.

ACTION 9 With both RVLIS channels inoperable, restore one channel to OPERABLE status within 7 days or submit a special report in accordance with Specification 6.9.4.

ACTION 10 With the number of OPERABLE Channels less than required by the minimum channels OPERABLE requirements, initiate the preplanned alternate method of monitoring the appropriate parameter within 72 hours, and:

1) either restore the inoperable Channel(s) to OPERABLE status within 7 days of the event, or

2) prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the actions taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

TABLE 4.3-11
SURVEILLANCE REQUIREMENTS FOR ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	CHANNEL CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Reactor Coolant Outlet Temperature - T_{HOT} (Wide Range)	M	R	N.A.
2. Reactor Coolant Inlet Temperature - T_{COLD} (Wide Range)	M	R	N.A.
3. Reactor Coolant Pressure (Wide Range)	M	R	N.A.
4. Pressurizer Water Level	M	R	N.A.
5. Steam Line Pressure	M	R	N.A.
6. Steam Generator Water Level (Narrow Range)	M	R	N.A.
7. Steam Generator Water Level (Wide Range)	M	R	N.A.
8. Refueling Water Storage Tank Water Level	M	R	N.A.
9. deleted			
10. Auxiliary Feedwater Flow Rate	S/U#	R	N.A.
11. Reactor Coolant System Subcooling Margin Monitor	M	N.A.*	N.A.

#Auxiliary Feedwater System is used on each startup and flow rate indication is verified at that time.

*The instruments used to develop RCS subcooling margin are calibrated on an 18 month cycle; the monitor will be compared quarterly with calculated subcooling margin for known input values.

TABLE 4.3-11 (Continued)
SURVEILLANCE REQUIREMENTS FOR
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	CHANNEL CHECKS	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
12. PORV Position Indicator	M	N.A.	R
13. PORV Block Valve Position Indicator	M	N.A.	Q*
14. Pressurizer Safety Valve Position Indicator	M	N.A.	R
15. Containment Pressure - Narrow Range	M	R	N.A.
16. Containment Pressure - Wide Range	M	R	N.A.
17. Containment Water Level - Wide Range	M	R	N.A.
18. Core Exit Thermocouples	M	R	N.A.
19. Reactor Vessel Level Instrumentation System (RVLIS)	M	R	N.A.
20. Containment High Range Accident Radiation monitor	S	R	Q
21. Main Steamline Discharge (Safety Valves and Atmospheric Steam Dumps) Monitor	S	R	Q

* Unless the block valve is closed in order to meet the requirements of Action b, or c in specification 3.4.5.

INSTRUMENTATION

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.8 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3-12 shall be OPERABLE to ensure that the limits of ODCM Control 3.11.1.1 are not exceeded.

APPLICABILITY: At all times.

ACTION:

a. Not Used

b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3-12. Exert best efforts to return the instrument to OPERABLE status within 30 days and, if unsuccessful, explain in the next annual radioactive effluent release report why the inoperability was not corrected in a timely manner.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.8 Each radioactive liquid effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3-12.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Not Used		
2. Not Used		
3. Not Used		
4. TANK LEVEL INDICATING DEVICES		
a. Temporary Outside Storage Tanks as Required	1	30

TABLE NOTATION

ACTION 26 - Not Used

ACTION 27 - Not Used

ACTION 28 - Not Used

ACTION 29 - Not Used

ACTION 30 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, liquid additions to this tank may continue for up to 30 days provided the tank liquid level is estimated during all liquid additions to the tank.

ACTION 31 - Not Used

TABLE 4.3-12
RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Not Used				
2. Not Used				
3. Not Used				
4. TANK LEVEL INDICATING DEVICES**				
a. Temporary Outside Storage Tanks as Required	D*	N.A.	R	Q

TABLE NOTATION

* During liquid additions to the tank.

** If tank level indication is not provided, verification will be done by visual inspection.

Pages 3/4 3-57 through 3/4 3-64 Deleted

INSTRUMENTATION

POWER DISTRIBUTION MONITORING SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.3.14 The Power Distribution Monitoring System (PDMS) shall be OPERABLE with:

a. A minimum of the following inputs from the plant available for use by the PDMS as defined in Table 3.3-14.

   1. Control Bank Position

   2. T_{cold}

   3. Reactor Power Level

   4. NIS Power Range Detector Section Signals

b. Core Exit Thermocouples (T/C) meeting the criteria:

   1. At least 25% operable T/C with at least 2 T/C per quadrant, and

   2. The T/C pattern has coverage of all interior fuel assemblies (no face along the baffle), within a chess knight's move, radially, from a responding, calibrated T/C, or

   3. At least 25%, operable T/C with at least 2 T/C per quadrant, and the installed PDMS calibration was determined within the last 31 Effective Full Power Days (EFPD).

   4. The T/C temperatures used by the PDMS are calibrated via cross calibration with the loop temperature measurement RTDs, and using the T/C flow mixing factors determined during installed PDMS calibration.

c. An installed PDMS calibration satisfying the criteria:

   1. The initial calibration in each operating cycle is determined using measurements from at least 75% of the incore movable detector thimbles obtained at a THERMAL POWER greater than 25% of RATED THERMAL POWER.

   2. The calibration is determined using measurements from at least 50% of the incore movable detector thimbles at any time except as specified in 3.3.3.14.c.1, and

   3. The calibration is determined using a minimum of 2 detector thimbles per core quadrant.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILTY.- MODE 1, above 25% RATED THERMAL POWER (RTP)

ACTION:

With any of the operability criteria listed in 3.3.3.14.a, 3.3.3.14.b, or 3.3.3.14.c not met, either correct the deficient operability condition, or declare the PDMS inoperable and use the incore movable detector system, satisfying the OPERABILITY requirements listed in Specification 3.3.3.2, to obtain any required core power distribution measurements. Increase the measured core peaking factors using the values listed in the COLR for the PDMS inoperable condition.

The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.14.1 The operability criteria listed in 3.3.3.14.a, 3.3.3.14.b, and 3.3.3.14.c shall be verified to be satisfied prior to acceptance of the PDMS core power distribution measurement results.

4.3.3.14.2 Calibration of the PDMS is required:

a. At least once every 180 Effective Full Power Days when the minimum number and core coverage criteria as defined in 3.3.3.14.b.1 and 3.3.3.14.b.2 are satisfied, or

b. At least once every 31 Effective Full Power Days when only the minimum number criterion as defined in 3.3.3.14.b.3 is satisfied.

TABLE 3.3-14

REQUIRED PDMS PLANT INPUT INFORMATION

PLANT INPUT INFORMATION	AVAILABLE INPUTS	MINIMUM NO. OF VALID INPUTS	APPLICABLE MODES
Control Bank Position	4	4[a]	1[c]
T_{cold}	4	2	1[c]
Reactor Power Level	3	1[b]	1[c]
NIS Power Range Excore Detector Section Signals	8	6[d]	1[c]

TABLE NOTATIONS

a. Determined from either valid Demand Position or the average of the valid individual RCCA position indications for all RCCAs in the Control Bank.

b. Determined from either the reactor THERMAL POWER derived using a valid secondary calorimetric measurement, the average NIS Power Range Detector Power, or the average RCS Loop ΔT.

c. Greater than 25% RTP.

d. Comprised of an upper and lower detector section signal per Power Range Channel; a minimum of 3 OPERABLE channels required.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

STARTUP AND POWER OPERATION

LIMITING CONDITION FOR OPERATION

3.4.1.1 All reactor coolant loops shall be in operation.

APPLICABILITY: MODES 1 and 2.*

ACTION:

With less than the above required coolant loops in operation, be in at least HOT STANDBY within 1 hour.

SURVEILLANCE REQUIREMENT

4.4.1.1 The above required reactor coolant loops shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

*See Special Test Exception 3.10.4.

REACTOR COOLANT SYSTEM

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 a. At least two of the reactor coolant loops listed below shall be OPERABLE:

1. Reactor Coolant Loop 21 and its associated steam generator and reactor coolant pump,

2. Reactor Coolant Loop 22 and its associated steam generator and reactor coolant pump,

3. Reactor Coolant Loop 23 and its associated steam generator and reactor coolant pump,

4. Reactor Coolant Loop 24 and its associated steam generator and reactor coolant pump.

b. At least one of the above coolant loops shall be in operation* when the rod control system is deenergized**.

c. All of the above coolant loops shall be in operation when the rod control system is energized**.

APPLICABILITY: MODE 3

ACTION:

a. With less than the above required reactor coolant loops OPERABLE, restore the required loops to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop to operation.

REACTOR COOLANT SYSTEM

HOT STANDBY

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 At least the above required reactor coolant pumps, if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.2.2 At least one cooling loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

4.4.1.2.3 The required steam generator(s) shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 5% (narrow range) at least once per 12 hours.

---

*All reactor coolant pumps may be de-energized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration (2) core outlet temperature is maintained at least 10°F below saturation temperature, and (3) the rod control system is de-energized**

**The rod control system shall be considered de-energized when one or more of the following conditions exist:

1) Both Rod Drive MG set motor breakers are open.

2) Both Rod Drive MG set generator breakers are open.

3) A combination of at least three of the Reactor Trip and/or Reactor Trip Bypass Breakers are open.

If none of the above conditions for de-energizing the rod control system are met; the system shall be considered energized.

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.3 a. At least two of the coolant loops listed below shall be OPERABLE:

1. Reactor Coolant Loop 21 and its associated steam generator and reactor coolant pump,*

2. Reactor Coolant Loop 22 and its associated steam generator and reactor coolant pump,*

3. Reactor Coolant Loop 23 and its associated steam generator and reactor coolant pump,*

4. Reactor Coolant Loop 24 and its associated steam generator and reactor coolant pump,*

5. Residual Heat Removal Loop 21,

6. Residual Heat Removal Loop 22.

b. At least one of the above coolant loops shall be in operation.**

APPLICABILITY: MODE 4.

ACTION:

a. With less than the above required loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible; be in COLD SHUTDOWN within 20 hours.

b. With no coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop to operation.

*A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to 312°F unless 1) the pressurizer water volume is less than 1650 cubic feet (equivalent to approximately 92% of level) or 2) the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

**All reactor coolant pumps and residual heat removal pumps may be de-energized for up to 1 hour provided 1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

SURVEILLANCE REQUIREMENTS

4.4.1.3.2 The required reactor coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.3.3 The required steam generator(s) shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 5% (narrow range) at least once per 12 hours.

4.4.1.3.4 At least one coolant loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.4 Two# residual heat removal loops shall be OPERABLE* and at least one RHR loop shall be in operation.**

APPLICABILITY: MODE 5.##

ACTION:

a. With less than the above required loops operable, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4 At least one residual heat removal loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

One RHR loop may be inoperable for up to two hours for surveillance testing, provided the other RHR loop is OPERABLE and in operation. Additionally, four filled reactor coolant loops, with at least two steam generators with their secondary side water levels greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop.

A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to 312°F unless 1) the pressurizer water volume is less than 1650 cubic feet (equivalent to approximately 92% of level), or 2) the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

* Systems supporting RHR loop operability may be excepted as follows:

a. The normal or emergency power source may be inoperable.

** The residual heat removal pumps may be de-energized for up to 2 hours provided 1) no operations are permitted that would cause dilution of the reactor coolant system boron concentration, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

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REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY VALVES

SAFETY VALVES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2 A minimum of one pressurizer code safety valve shall be OPERABLE* with a lift setting of 2485 psig ± 3%.**,***

APPLICABILITY: Mode 4 and 5

ACTION:

With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE RHR loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

* While in Mode 5, an equivalent size vent pathway may be used provided that the vent pathway is not isolated or sealed.

** The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

*** Following testing the lift setting shall be reset to within ± 1%.

3/4.4.3 SAFETY VALVES - OPERATING

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting of 2485 psig ± 3%.*,**

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.3 No additional Surveillance Requirements other than those required by Specification 4.0.5.

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** Following testing the lift setting shall be reset to ± 1%.

3/4.4.4 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.4 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1650 cubic feet (92% indicated level), and at least two groups of pressurizer heaters each having a capacity of ≥ 150 kw and capable of being powered from an emergency power supply.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the pressurizer inoperable due to an inoperable emergency power supply to the pressurizer heaters either restore the inoperable emergency power supply within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.4.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.4.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by measuring circuit current at least once each refueling outage.

4.4.4.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by manually transferring power from the normal to the emergency power supply and energizing the heaters.

REACTOR COOLANT SYSTEM

3/4.4.5 RELIEF VALVES

LIMITING CONDITION FOR OPERATION

===

3.4.5 Two power relief valves (PORVs) and their associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or both PORVs inoperable because of excessive seat leakage, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) with power maintained to the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one PORV inoperable due to causes other than excessive seat leakage, within 1 hour either restore the PORV to OPERABLE status or close its associated block valve and remove power from the block valve; restore the PORV to OPERABLE status within the following 72 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With both PORVs inoperable due to causes other than excessive seat leakage, within 6 hours either restore at least one PORV to OPERABLE status or close the associated block valves and remove power from the block valves and be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours. Restore the remaining PORV to OPERABLE status within 72 hours from failure of that valve to meet the Limiting Condition for Operation.

d. With one block valve inoperable, within 1 hour restore the block valve to OPERABLE status or place the associated PORV in manual control; restore the block valve to operable status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

e. With both block valves inoperable, within 1 hour restore the block valves to OPERABLE status or place the associated PORVs in manual control; restore at least one block valve to OPERABLE status within the next 6 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours. Restore the remaining block valve to OPERABLE status within 72 hours from failure of that valve to meet the Limiting Condition for Operation.

3/4.4.5 RELIEF VALVES

SURVEILLANCE REQUIREMENTS

4.4.5.1 In addition to the requirements of Specification 4.0.5, each PORV shall be demonstrated OPERABLE at least once per 18 months by:

a. Operating the PORV through one complete cycle of full travel during MODES 3 or 4, and

b. Operating solenoid valves, air control valves, and check valves on associated air accumulators in PORV control systems through one complete cycle of full travel, and

c. Performing a CHANNEL CALIBRATION of the actuation instrumentation.

4.4.5.2 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel unless the block valve is closed in order to meet the requirements of ACTION b, or c in Specification 3.4.5.

3/4.4.6 STEAM GENERATOR (SG) TUBE INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.6 SG tube integrity shall be maintained and all SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a.* With one or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program:

1. Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection within 7 days; and

2. Plug the affected tube(s) in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following the next refueling outage or SG tube inspection.

b. With SG tube integrity not maintained or the required Action of a. above not met, be in at least HOT STANDBY within 6 hours and in at least COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 Verify SG tube integrity in accordance with the Steam Generator Program.

4.4.6.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following a SG tube inspection

* Separate Action is allowed for each SG tube.

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REACTOR COOLANT SYSTEM

3/4.4.7 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.7.1 The following Reactor Coolant System leakage detection systems shall be OPERABLE:

a. The containment atmosphere particulate radioactivity monitoring system,

b. The containment pocket sump level monitoring system, and

c. Either the containment fan cooler condensate flow rate or the containment atmosphere gaseous radioactivity monitoring system.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only two of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required gaseous and/or particulate radioactivity monitoring system is inoperable; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.7.1 The leakage detection systems shall be demonstrated OPERABLE by:

a. Containment atmosphere particulate and gaseous (if being used) monitoring systems-performance of CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies specified in Table 4.3-3.

b. Containment pocket sump level and containment fan cooler condensate flow rate (if being used) monitoring systems-performance of CHANNEL CALIBRATION at least once per 18 months.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.7.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 GPM UNIDENTIFIED LEAKAGE,

c. 150 gallons per day primary-to-secondary leakage through any one steam generator, and

d. 10 GPM IDENTIFIED LEAKAGE from the Reactor Coolant System, and

e. NOT USED

f. 1 GPM leakage at a Reactor Coolant System pressure of 2230 ±20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

APPLICABILITY: MODES 1, 2, 3 and 4

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, or primary-to-secondary leakage not within limit, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, and primary-to-secondary leakage, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.7.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere particulate radioactivity monitor at least once per 12 hours.

b. Monitoring the containment sump inventory at least once per 12 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c*. Verifying primary-to-secondary leakage is = 150 gallons per day through any one steam generator at least once per 72 hours during steady state operation,

d*. Performance of a Reactor Coolant System water inventory balance** at least once per 72 hours. The water inventory balance shall be performed with the plant at steady state conditions. The provisions of specification 4.0.4 are not applicable for entry into Mode 4, and

e. Monitoring the reactor head flange leakoff system at least once per 24 hours.

4.4.7.2.2 Each Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1 shall be demonstrated OPERABLE pursuant to Specification 4.0.5, except that in lieu of any leakage testing required by Specification 4.0.5, each valve shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once per 18 months.

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 72 hours or more and if leakage testing has not been performed in the previous 9 months.

c. Prior to returning the valve to service following maintenance repair or replacement work on the valve.

b. For the Residual Heat Removal and Safety Injection Systems hot and cold leg injection valves and accumulator valves listed in Table 3.4-1 the testing will be done within 24 hours following valve actuation due to automatic or manual action or flow through the valve. For all other systems testing will be done once per refueling.

The provisions of specification 4.0.4 are not applicable for entry into MODE 3 or 4.

**Not required to be completed until 12 hours after establishment of steady state operation.*

***Not applicable to primary-to-secondary leakage.*

TABLE 3.4-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NO	FUNCTION
21SJ43	Safety Injection (L.P. from RHR Pumps to Cold Legs)
22SJ43	Safety Injection (L.P. from RHR Pumps to Cold Legs)
23SJ43	Safety Injection (L.P. from RHR Pumps to Cold Legs)
24SJ43	Safety Injection (L.P. from RHR Pumps to Cold Legs)
21SJ55	Safety Injection (Accumulator Discharge to Cold Legs)
22SJ55	Safety Injection (Accumulator Discharge to Cold Legs)
23SJ55	Safety Injection (Accumulator Discharge to Cold Legs)
24SJ55	Safety Injection (Accumulator Discharge to Cold Legs)
21SJ56	Safety Injection (Accumulator Discharge to Cold Legs)
22SJ56	Safety Injection (Accumulator Discharge to Cold Legs)
23SJ56	Safety Injection (Accumulator Discharge to Cold Legs)
24SJ56	Safety Injection (Accumulator Discharge to Cold Legs)
21SJ17	Safety Injection (Boron Injection to Cold Legs)
22SJ17	Safety Injection (Boron Injection to Cold Legs)
23SJ17	Safety Injection (Boron Injection to Cold Legs)
24SJ17	Safety Injection (Boron Injection to Cold Legs)
2SJ150	Safety Injection (Boron Injection to Cold Legs)
21SJ139	Safety Injection (H.P. from SI Pumps to Hot Legs)
22SJ139	Safety Injection (H.P. from SI Pumps to Hot Legs)
23SJ139	Safety Injection (H.P. from SI Pumps to Hot Legs)
24SJ139	Safety Injection (H.P. from SI Pumps to Hot Legs)
21SJ156	Safety Injection (H.P. from SI Pumps to Hot Legs)
22SJ156	Safety Injection (H.P. from SI Pumps to Hot Legs)
23SJ156	Safety Injection (H.P. from SI Pumps to Hot Legs)
24SJ156	Safety Injection (H.P. from SI Pumps to Hot Legs)
21SJ144	Safety Injection (H.P. from SI Pumps to Cold Legs)
22SJ144	Safety Injection (H.P. from SI Pumps to Cold Legs)
23SJ144	Safety Injection (H.P. from SI Pumps to Cold Legs)
24SJ144	Safety Injection (H.P. from SI Pumps to Cold Legs)
2RH1	RHR Suction from Hot Leg No. 21
2RH2	RHR Suction from Hot Leg No. 21
23RH27	RHR Discharge to Hot Leg No. 23
24RH27	RHR Discharge to Hot Leg No. 24

PAGES 3/4 4-20 THROUGH 3/4 4-22 DELETED

3/4.4.9 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.9 The specific activity of the primary coolant shall be limited to:

a. ≤ 1.0 μCi/gram DOSE EQUIVALENT I-131, and

b. ≤ 100/Ē μCi/gram.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1, 2 and 3*

a. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in at least HOT STANDBY with T_{avg} < 500°F within 6 hours.

b. With the specific activity of the primary coolant > 100/Ē μCi/gram, be in at least HOT STANDBY with T_{avg} < 500°F within 6 hours.

c. LCO 3.0.4.c is applicable.

MODES 1, 2, 3, 4 and 5

a. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 or > 100/Ē μCi/gram, perform the sampling and analysis requirements of item 4a of Table 4.4-4 until the specific activity of the primary coolant is restored to within its limits.

SURVEILLANCE REQUIREMENTS

4.4.9 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

*With T_{avg} ≥ 500°F.

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TABLE 4.4-4

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Activity Determination	At least once per 72 hours	1, 2, 3, 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination	1 per 6 months*	1
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135	a) Once per 4 hours, whenever the specific activity exceeds 1.0 μCi/gram DOSE EQUIVALENT I-131 or 100/$\bar{E}$ μCi/gram, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.	1, 2, 3

#Until the specific activity of the primary coolant system is restored within its limits.

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

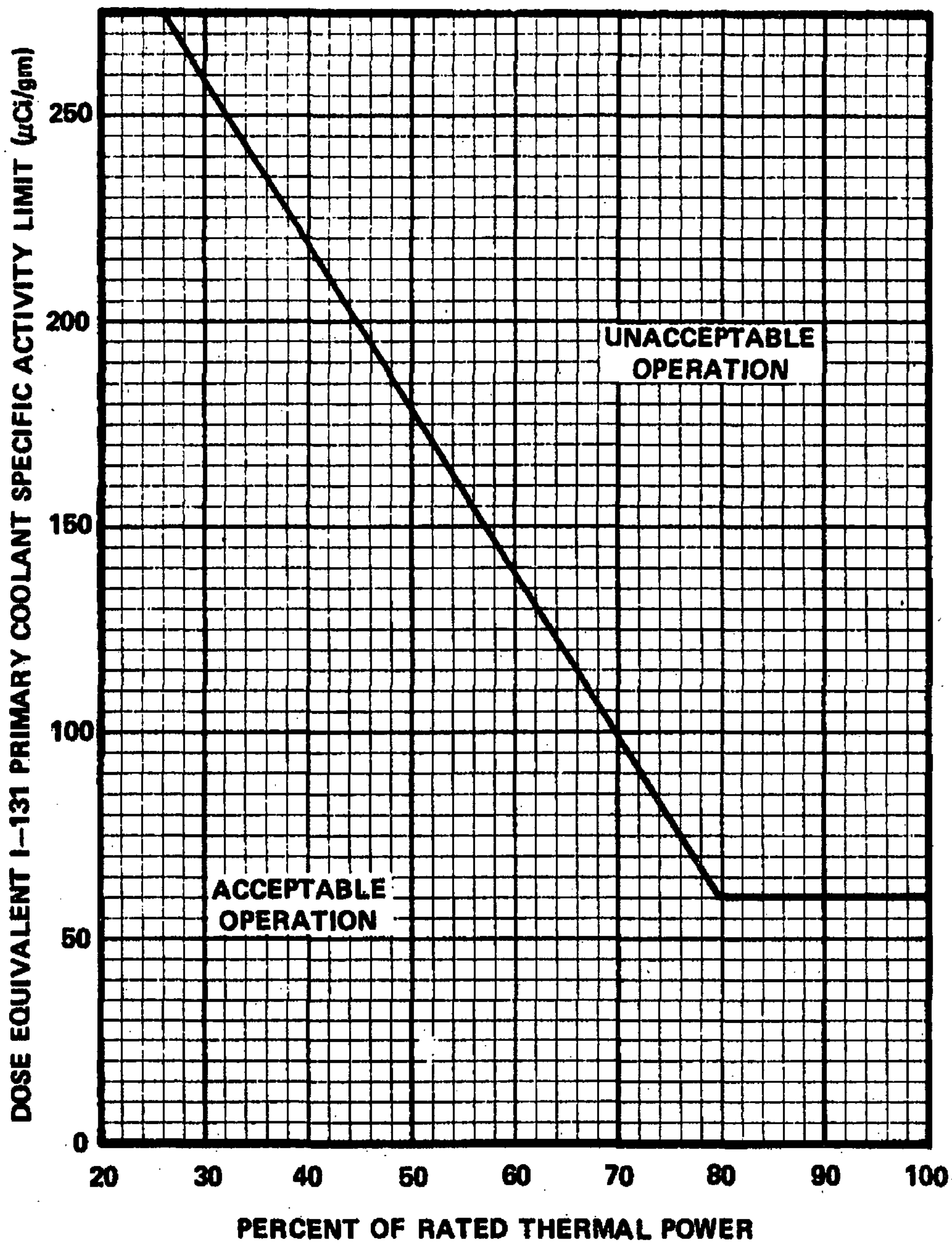

FIGURE 3.4-1

DOSE EQUIVALENT I–131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity >1.0μCi/gram Dose Equivalent I-131

REACTOR COOLANT SYSTEM

3/4.4.10 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.10.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figures 3.4-2 and 3.4-3 during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 100°F in any one hour period, and

c. A maximum temperature change of less than or equal to 5°F in any one hour period, during hydrostatic testing operations above system design pressure.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limit within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the RCS T_{avg} and pressure to less than 200°F and 500 psig, respectively, within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.10.1.1 The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

4.4.10.1.2 The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties, at the intervals required by 10 CFR 50, Appendix H. The results of these examinations shall be used to update Figures 3.4-2 and 3.4-3.

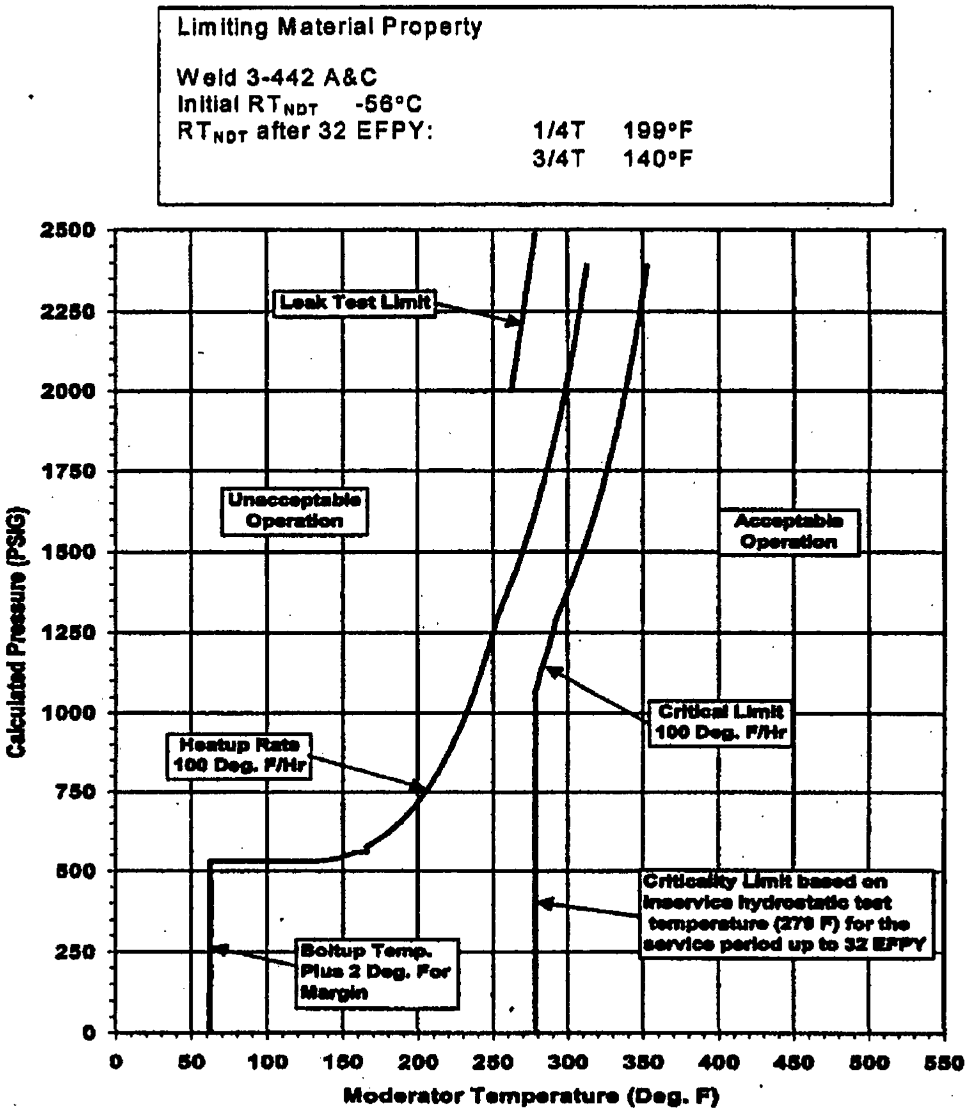

Figure 3.4-2

SALEM UNIT 2 REACTOR COOLANT SYSTEM HEATUP LIMITATIONS APPLICABLE FOR THE FIRST 32 EFPY WITH MAXIMUM HEATUP RATE OF 100 F/HR. CURVE CONTAINS MARGIN FOR INSTRUMENT ERRORS

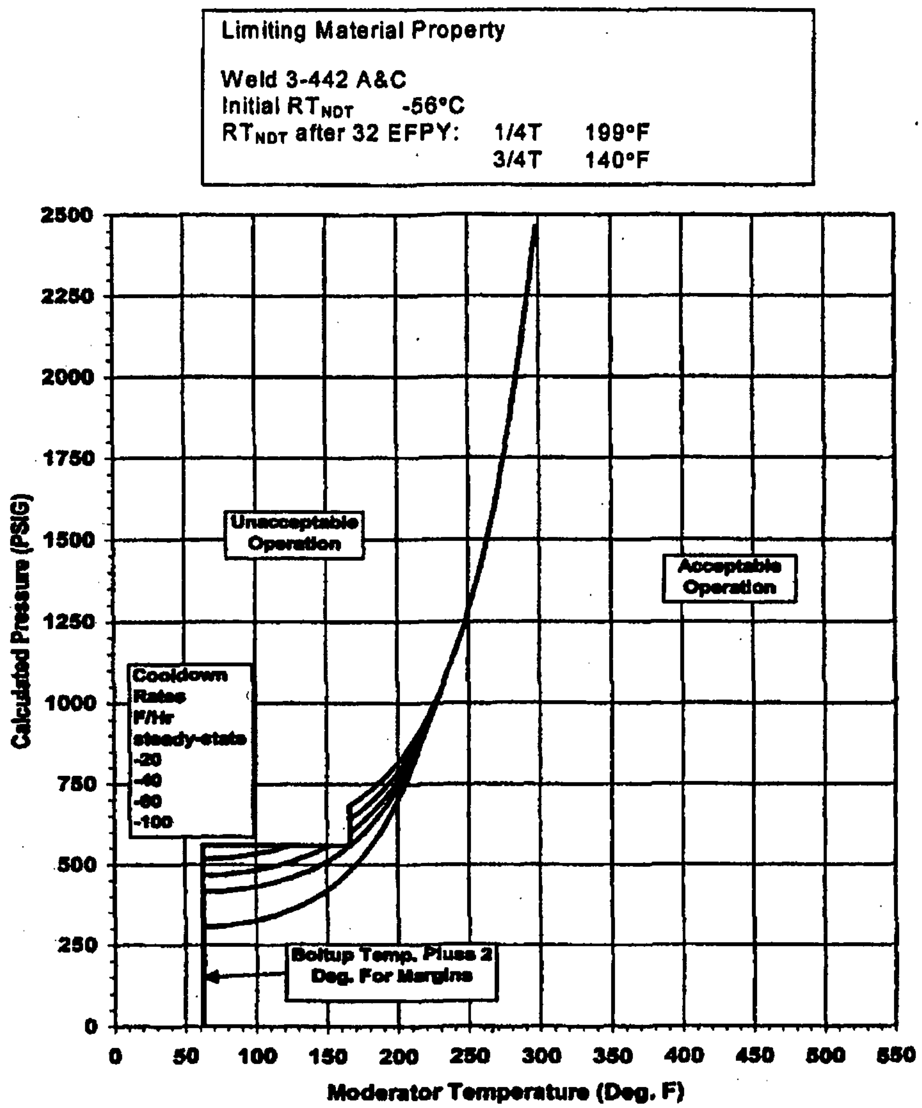

Figure 3.4-3

SALEM UNIT 2 REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS APPLICABLE FOR THE FIRST 32 EFPY WITH MAXIMUM COOLDOWN RATE OF 100 F/HR. CURVE CONTAINS MARGIN FOR INSTRUMENT ERRORS.

REACTOR COOLANT SYSTEM

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.10.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 200°F in any one hour period, and

c. A maximum spray water temperature differential of 320°F.

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.10.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown. The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during auxiliary spray operation.

OVERPRESSURE PROTECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.10.3 At least one of the following overpressure protection systems shall be OPERABLE:

a. Two Pressurizer Overpressure Protection System relief valves (POPS) with a lift setting of less than or equal to 375 psig, or

b. The Reactor Coolant System (RCS) depressurized with an RCS vent of greater than or equal to 3.14 square inches.

APPLICABILITY: When the temperature of one or more of the RCS cold legs is less than or equal to 312°F, except when the reactor vessel head is removed.

ACTION:

a. With one POPS inoperable in MODE 4 and the temperature of one or more of the RCS cold legs is less than or equal to 312°F, restore the inoperable POPS to OPERABLE status within 7 days or depressurize and vent the RCS through a 3.14 square inch vent(s) within the next 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

b. With one POPS inoperable in MODES 5 or 6 with the Reactor Vessel Head installed, restore the inoperable POPS to OPERABLE status within 24 hours, or complete depressurization and venting of the RCS through at least a 3.14 square inch vent(s) within the next 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

c. With both POPSs inoperable, depressurize and vent the RCS through a 3.14 square inch vent(s) within 8 hours; maintain the RCS in a vented condition until both POPSs have been restored to OPERABLE status.

d. In the event either the POPS or the RCS vent(s) are used to mitigate a RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the POPS or vent(s) on the transient and any corrective action necessary to prevent recurrence.

e. LCO 3.0.4.b is not applicable when entering MODE 4.

SURVEILLANCE REQUIREMENTS

4.4.10.3.1 Each POPS shall be demonstrated OPERABLE by:

SURVEILLANCE REQUIREMENTS (Continued)

a. Performance of a CHANNEL FUNCTIONAL TEST on the POPS actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the POPS is required OPERABLE and at least once per 31 days thereafter when the POPS is required OPERABLE.

b. Performance of a CHANNEL CALIBRATION on the POPS actuation channel at least once per 18 months.

c. Verifying the POPS isolation valve is open at least once per 72 hours when the POPS is being used for overpressure protection.

d. Testing pursuant to Specification 4.0.5.

4.4.10.3.2 The RCS vent(s) shall be verified to be open at least once per 12 hours* when the vent(s) is being used for overpressure protection.

*Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

3.4.11 STRUCTURAL INTEGRITY

ASME CODE CLASS 1, 2 and 3 COMPONENTS

LIMITING CONDITION FOR OPERATION

3.4.11.1 The structural integrity of ASME Code Class 1, 2 and 3 components shall be maintained in accordance with Specification 4.4.11.1.

APPLICABILITY: ALL MODES.

ACTION:

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

SURVEILLANCE REQUIREMENTS

4.4.11.1 In addition to the requirements of Specification 4.0.5, each Reactor Coolant Pump flywheel shall be inspected per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

4.4.11.2 Augmented Inservice Inspection Program for Steam Generator Channel Heads - The No. 21 Steam Generator channel head shall be ultrasonically inspected in a selected area during each of the first three refueling outages using the same ultrasonic inspection procedures and equipment used to generate the baseline data. These inservice ultrasonic inspections shall verify that the cracks observed in the stainless steel cladding prior to operation have not propagated into the base material.

REACTOR COOLANT SYSTEM

3/4.4.12 HEAD VENTS

LIMITING CONDITION FOR OPERATION

3.4.12 Four reactor vessel head vent paths shall be operable with the vent paths closed. A vent path consists of at least two head vent valves in series, powered from vital sources, and associated flowpath.

APPLICABILITY: MODES 1, 2, 3 AND 4.

ACTION:

a. With one, two or three reactor vessel head vent path(s) inoperable, STARTUP and/or POWER OPERATION may continue provided the inoperable vent path(s) is maintained closed with the valve actuators key locked in the closed position; restore the inoperable vent path(s) to OPERABLE status within 30 days, or, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With four reactor vessel head vent paths inoperable; maintain the inoperable vent paths closed with power removed from the valve actuators of all the vent valves in the inoperable vent paths, and restore at least one of the vent paths to OPERABLE status within 72 hours or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.12 Reactor vessel head vent system vent paths shall be demonstrated OPERABLE at least once per 18 months by:

1. Verifying all manual isolation valves in each vent path are locked in the open position.

2. Cycling each valve in the vent paths through at least one complete cycle of full travel from the control room during COLD SHUTDOWN or REFUELING.

3. Verifying flow through the reactor vessel head vent system vent path during venting.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system accumulator shall be OPERABLE with:

a. The isolation valve open,

b. A contained volume of between 6223 and 6500 gallons of borated water,

c. A boron concentration of between 2200 and 2500 ppm, and

d. A nitrogen cover-pressure of between 595.5 and 647.5 psig.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. With one accumulator inoperable, except as a result of a closed isolation valve or boron concentration outside the required limits, restore the inoperable accumulator to OPERABLE status within 24 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With one accumulator inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in HOT STANDBY within 24 hours and be in HOT SHUTDOWN within the next 12 hours.

c. With the boron concentration of one accumulator outside the required limits, restore the boron concentration to within the required limits within 72 hours or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than or equal to 1000 psig within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the water level and nitrogen cover-pressure in the tanks, and

2. Verifying that each accumulator isolation valve is open.

* Pressurizer Pressure above 1000 psig.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the accumulator solution.

c. At least once per 31 days when the RCS pressure is greater than 1000 psig by verifying that the power lockout switch is in lockout.

d. At least once per 18 months by verifying that each accumulator isolation valve opens automatically upon receipt of a safety injection test signal.

ECCS SUBSYSTEMS - $T_{avg} \geq 350°F$

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of the following injection systems:

a. One OPERABLE centrifugal charging pump and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

   1. Discharging into each Reactor Coolant System (RCS) cold leg.

b. One OPERABLE safety injection pump and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

   1. Discharging into each RCS cold leg, and; upon manual initiation,

   2. Discharging into its two associated RCS hot legs.

c. One OPERABLE residual heat removal pump and associated residual heat removal heat exchanger and flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation and;

   1. Discharging into each RCS cold leg.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

ECCS SUBSYSTEMS - T_{avg} ≥ 350°F

ACTION (Continued):

c. With both ECCS subsystems inoperable for surveillance testing, restore at least one subsystem to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours and at least COLD SHUTDOWN within the subsequent 24 hours.

SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying that the following valves are in the indicated positions with power to the valve operators removed:

Valve Number	Valve Function	Valve Position
a. 2 SJ 69	a. RHR pump suction	a. open
b. 2 SJ 30	b. SI pump suction	b. open
c. 21 SJ 40	c. SI discharge to hot legs	c. closed
d. 22 SJ 40	d. SI discharge to hot legs	d. closed
e. 2 RH 26	e. RHR discharge to hot legs	e. closed
f. 21 SJ 49	f. RHR discharge to cold legs	f. open
g. 22 SJ 49	g. RHR discharge to cold legs	g. open
h. 2 CS 14#	h. Spray additive tank discharge	h. open
i. 2 SJ 135	i. SI discharge to cold legs	i. open
j. 2 SJ 67	j. SI recirc. line isolation	j. open
k. 2 SJ 68	k. SI recirc. line isolation	k. open

2. Verifying that the following valves are in the indicated positions:

Valve Number	Valve Function	Valve Position
a. 21 RH 18	a. RHR crosstie valve	a. Open
b. 22 RH 19	b. RHR crosstie valve	b. Open

b. At least once per 31 days by:

1. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

2. Verifying that the ECCS piping is full of water by venting the ECCS pump casings and accessible discharge piping high points.

#If inoperable, the applicable Technical Specification is 3.6.2.2.

SURVEILLANCE REQUIREMENTS (Continued)

c. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

   1. For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

   2. At least once daily (24 hour consecutive period) the areas affected within containment by containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

d. At least once per 18 months by:

   1. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

e. At least once per 18 months, during shutdown, by:

   1. Verifying that each automatic valve in the flow path actuates to its correct position on a safety injection test signal.

   2. Verifying that each of the following pumps start automatically upon receipt of a safety injection test signal:

      a) Centrifugal charging pump

      b) Safety injection pump

      c) Residual heat removal pump

SURVEILLANCE REQUIREMENTS (Continued)

f. By verifying that each of the following pumps develops the indicated Total Dynamic Head (TDH) when tested at the test flow point pursuant to Specification 4.0.5:

1. Centrifugal Charging pump ≥ 2338 psi TDH
2. Safety Injection pump ≥ 1369 psi TDH
3. Residual Heat Removal pump ≥ 165 psi TDH

g. By verifying the correct position of each of the following ECCS throttle valves:

1. Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE.

2. At least once per 18 months.

HPSI System Valve Number	LPSI System Valve Number
21 SJ 16	21 SJ 138
22 SJ 16	22 SJ 138
23 SJ 16	23 SJ 138
24 SJ 16	24 SJ 138
	21 SJ 143
	22 SJ 143
	23 SJ 143
	24 SJ 143

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1. For Safety Injection pumps, with a single pump running:

a) The sum of the injection line flow rates, excluding the highest flow rate, is ≥ 453 gpm, and

b) The total flow rate through all four injection lines is ≤ 647 gpm, and

c) The difference between any pair of injection line flow rates is ≤ 12.0 gpm, and

d) The total pump flow rate is ≤ 664 gpm in the cold leg alignment, and

e) The total pump flow rate is ≤ 654 gpm in the hot leg alignment.

2. For centrifugal charging pump, with a single pump running:

   a) The sum of the injection line flow rates, excluding the highest flow rate, is ≥ 306 gpm, and

   b) The total flow rate through all four injection lines is ≤ 444 gpm, and

   c) The difference between any pair of injection line flow rates is ≤ 10.5 gpm, and

   d) The total pump flow rate is ≤ 554 gpm.

i. The automatic interlock function of the RHR System shall be verified within the seven (7) days prior to placing the RHR System in service for cooling of the Reactor Coolant System. This shall be done by verifying with a test signal corresponding to a reactor coolant pressure of 375 psig or greater, that the 2RH1 and 2RH2 valves cannot be opened.

ECCS SUBSYSTEMS - T_{avg} <350°F

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE centrifugal charging pump# and associated flow path capable of taking suction from the refueling water storage tank and transferring suction to the residual heat removal pump discharge piping and;

1. Discharging into each Reactor Coolant System (RCS) cold leg.

b. One OPERABLE residual heat removal pump and associated residual heat removal heat exchanger and flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation and;

1. Discharging into each RCS cold leg, and; upon manual initiation,

2. Discharging into two RCS hot legs.

APPLICABILITY: MODE 4.

ACTION:

a. With no ECCS subsystem OPERABLE because of the inoperability of either the centrifugal charging pump or the flow path from the refueling water storage tank, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 hours.

b. With no ECCS subsystem OPERABLE because of the inoperability of either the residual heat removal heat exchanger or residual heat removal pump, restore at least one ECCS subsystem to OPERABLE status or maintain the Reactor Coolant System T_{avg} lessthan 350°F by use of alternate heat removal methods.

c. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

d. LCO 3.0.4.b is not applicable to ECCS high head subsystem

A maximum of one safety injection pump or one centrifugal charging pump shall be OPERABLE in MODE 4 when the temperature of one or more of the RCS cold legs is less than or equal to 312°F, Mode 5, or Mode 6 when the head is on the reactor vessel.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE per applicable Surveillance Requirements of 4.5.2.

4.5.3.2 All safety injection pumps and centrifugal charging pumps, except the above required OPERABLE pump, shall be demonstrated to be inoperable at least once per 12 hours while in MODE 4 and the temperature of one or more of the RCS cold legs is less than or equal to 312°F, MODE 5, or MODE 6 when the head is on the reactor vessel by either of the following methods:

a. By verifying that the motor circuit breakers have been removed from their electrical power supply circuits or,

b. By verifying that the pump is in a recirculation flow path and that two independent means of preventing RCS injection are utilized.

EMERGENCY CORE COOLING SYSTEMS

SEAL INJECTION FLOW

LIMITING CONDITION FOR OPERATION

3.5.4 Reactor coolant pump seal injection flow shall be ≤40 gpm with centrifugal charging pump discharge header pressure ≥2430 psig and the charging flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3

ACTION:

With seal injection flow not within the limit, adjust manual seal injection throttle valves to give a flow within the limit with the charging pump discharge pressure ≥2430 psig and the charging flow control valve full open within 4 hours, or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 At least once per 31 days, verify manual seal injection throttle valves are adjusted to give a flow within the limit with centrifugal charging pump discharge header pressure ≥2430 psig, and the charging flow control valve full open.

The provisions of Specification 4.0.4 are not applicable for entry into Mode 3. This exemption is allowed for up to 4 hours after the Reactor Coolant System pressure stabilizes at 2235 ± 20 psig.

EMERGENCY CORE COOLING SYSTEMS

REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.5 The refueling water storage tank (RWST) shall be OPERABLE with:

a. A contained volume of between 364,500 and 400,000 gallons of borated water.

b. A boron concentration of between 2,300 and 2,500 ppm, and

c. A minimum water temperature of 35°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the refueling water storage tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.5 The RWST shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the water level in the tank, and

2. Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is < 35°F.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a1. At least once per 31 days by verifying that each containment manual valve or blind flange that is located outside containment and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls. Valves and blind flanges in high radiation areas may be verified by use of administrative controls.

a2. Prior to entering Mode 4 from Mode 5 if not performed within the last 92 days by verifying that each containment manual valve or blind flange that is located inside containment and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls. Valves and blind flanges in high radiation areas may be verified by use of administrative controls.

b. By verifying that each containment air lock is OPERABLE per Specification 3.6.1.3.

c. After each closing of a penetration subject to Type B testing, except containment air locks, if opened following a Type A or B test, by leak rate testing in accordance with the Containment Leakage Rate Testing Program.

d. At least once per 12 hours by verifying that the surveillance requirements of 4.6.2.3.a are met for penetrations associated with the containment fan coil units.

e. At least once per 18 months by verifying that the surveillance requirements of 4.6.2.3.d are met for penetrations associated with the containment fan coil units.

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate (Type A test) in accordance with the Containment Leakage Rate Testing Program.

b. A combined leakage rate in accordance with the Containment Leakage Rate Testing Program for all penetrations and valves subject to Type B and C tests.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With either (a) the measured overall integrated containment leakage rate (Type A test) not in accordance with the Containment Leakage Rate Testing Program or (b) with the measured combined leakage rate for all penetrations and valves subject to Types B and C tests not in accordance with the Containment Leakage Rate Testing Program, restore the leakage rate(s) to within the limit(s) prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated as follows:

a. Type A tests shall be in accordance with the Containment Leakage Rate Testing Program.

b. Type B and C tests shall be conducted in accordance with the Containment Leakage Rate Testing Program.

c. Air locks shall be tested and demonstrated OPERABLE in accordance with the Containment Leakage Rate Testing Program.

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CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and:

b. An overall air lock leakage rate in accordance with the Containment Leakage Rate Testing Program.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

Notes

(1) Entry and exit is permissible to perform repairs on the affected air lock components.

(2) Separate condition entry is allowed for each air lock.

(3) Required ACTIONS a.1, a.2, and a.3 are not applicable if both doors in the same air lock are inoperable and condition c. is entered.

(4) Required ACTIONS b.1, b.2, and b.3 are not applicable if both doors in the same air lock are inoperable and condition c. is entered.

(5) Enter applicable Conditions and required Actions of LCO 3.6.1, "Primary Containment," when air lock leakage results in exceeding the overall containment leakage rate.

a. One or more containment air locks with one containment airlock door inoperable:

1. Verify the OPERABLE door is closed in the affected air lock within 1 hour, and:

2. Lock the OPERABLE door closed in the affected air lock within 24 hours, and:

3. Verify the OPERABLE door is locked closed in the affected air lock once per 31 days. Entry and exit is permissible for 7 days (from initial LCO entry) under administrative controls if one door is inoperable in each air lock. Air lock doors in high radiation areas may be verified locked closed by administrative means.

b. One or more containment air locks with only the containment air lock interlock mechanism inoperable.

1. Verify an OPERABLE door is closed in the affected air lock within 1 hour, and:

2. Lock an OPERABLE door closed in the affected air lock within 24 hours, and:

3. Verify an OPERABLE door is locked closed in the affected air lock once per 31 days. Entry and exit of containment is permissible under the control of a dedicated individual for the duration of the entry to ensure only one door is open at a time. Air lock doors in high radiation areas may be verified locked closed by administrative means.

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATIONS (Continued)

c. One or more containment air locks inoperable for reasons other than condition a. or b.

1. Immediately initiate action to evaluate overall containment leakage per LCO 3.6.1, and:

2. Verify that at least one door is closed in the affected air lock within 1 hour, and:

3. Restore the air lock to OPERABLE status within 24 hours.

d. If the ACTIONS and associated completion times of a., b., or c. cannot be met, be in Hot Standby within 6 hours and in Cold Shutdown within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. By verifying seal leakage rate in accordance with the Containment Leakage Rate Testing program.

b. By conducting an overall air lock leakage test in accordance with the Containment Leakage Rate Testing Program.

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -1.5 and +0.3 psig.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

CONTAINMENT SYSTEMS

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall not exceed 120°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment average air temperature greater than 120°F, reduce the average air temperature to within the limit within 8 hours, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 Verify containment average air temperature is within limit at least once per twenty four hours.

CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITIONS FOR OPERATION

3.6.1.6 The structural integrity of the containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.6.1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the structural integrity of the containment not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.6.1 Containment Surfaces The structural integrity of the exposed accessible interior and exterior surfaces of the containment, including the liner plate, shall be determined in accordance with the Containment Leakage Rate Testing Program

4.6.1.6.2 Reports Any abnormal degradation of the containment structure detected during the above required inspections shall be evaluated for reportability pursuant to 10CFR50.72 and 10CFR50.73. The evaluation shall be documented and shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective action taken.

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Note that the elements of TS 3.6.1.7 and 4.6.1.7 were relocated to TS 3/4.6.3.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

CONTAINMENT SPRAY SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.1 Two independent containment spray systems shall be OPERABLE with each spray system capable of taking suction from the RWST and transferring suction to the RHR pump discharge.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one containment spray system inoperable, restore the inoperable spray system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the inoperable spray system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.1 Each containment spray system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying, that on recirculation flow, each pump develops a differential pressure of greater than or equal to 204 psid when tested pursuant to Specification 4.0.5.

c. At least once per 18 months during shutdown, by:

   1. Verifying that each automatic valve in the flow path actuates to its correct position on a Containment High-High pressure test signal.

   2. Verifying each spray pump starts automatically on a Containment High-High pressure test signal.

d. Following activities that could result in nozzle blockage, either evaluate the work performed to determine the impact to the containment spray system, or perform an air or smoke flow test through each spray header and verifying each spray nozzle is unobstructed.

SPRAY ADDITIVE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The spray additive system shall be OPERABLE with:

a. A spray additive tank containing a volume of between 2568 and 4000 gallons of between 30 and 32 percent by weight NaOH solution, and

b. Two spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a containment spray system pump flow.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the spray additive system inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the spray additive system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The spray additive system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 6 months by:

1. Verifying the solution level in the tank, and

2. Verifying the concentration of the NaOH solution by chemical analysis.

c. At least once per 18 months during shutdown, by verifying that each automatic valve in the flow path actuates to its correct position on a Containment High-High pressure test signal.

d. At least once per 5 years by:

1. Verifying a NaOH solution flow rate of 12.0 ± 3.0 gpm from the spray additive tank through sample valve 2CS61 with the spray additive tank at 2.5 ± 0.5 psig and

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the spray additive tank eductor flow will be 35 ± 3.5 gpm to each containment spray system. Testing may be performed by measuring the flow of borated water from the RWST through the installed 2" test line and Valve CS31; using this test line up with the spray pump operating in the recirculation mode and the RWST level at 41 feet ± 0.5 feet, the measured flow shall be 57 gpm ± 5.7 gpm.

CONTAINMENT SYSTEMS

CONTAINMENT COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.3 Five containment cooling fans shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one or two of the above required containment cooling fans inoperable, restore the inoperable cooling fan(s) to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With three or more of the above required containment cooling fans inoperable, restore at least three cooling fans to OPERABLE status within 1 hour or be in at least HOT STANDBY WITHIN the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore the remaining inoperable cooling fans to OPERABLE status within 7 days of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 Each containment cooling fan shall be demonstrated OPERABLE:

SURVEILLANCE REQUIREMENTS (Continued)

a. At least once per 12 hours by:

   1. Verifying the water level in each service water accumulator vessel is greater than or equal to 226 inches and less than or equal to 252 inches.

   2. Verifying the temperature in each service water accumulator vessel is greater than or equal to 55°F and less than or equal to 95°F.

   3. Verifying the nitrogen cover pressure in each service water accumulator vessel is greater than or equal to 135 psig and less than or equal to 160 psig.

b. At least once per 31 days by:

   1. Starting (unless already operating) each fan from the control room in low speed.

   2. Verifying that each fan operates for at least 15 minutes in low speed.

   3. Verifying a cooling water flow rate of greater than or equal to 2550 gpm to each cooler.

c. At least once per 18 months by verifying that on a safety injection test signal:

   1. Each fan starts automatically in low speed.

   2. The automatic valves and dampers actuate to their correct positions and that the cooling water flow rate to each cooler is greater than or equal to 2550 gpm.

d. At least once per 18 months by verifying that on a loss of offsite power test signal, each service water accumulator vessel discharge valve response time is within limits.

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each containment isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

NOTE 1

Penetration flow paths, except for the containment purge valves, may be unisolated intermittently under administrative controls.

Note 2

A containment purge valve is not a required containment isolation valve when its flow path is isolated with a testable blind flange tested in accordance with SR 4.6.1.2.b. The *required* containment purge supply and exhaust isolation valves shall be closed. (Valves immobilized in shut position with control air to valve operators isolated and tagged out of service).

NOTE 3

The containment pressure-vacuum relief isolation valves may be opened on an intermittent basis, under administrative control, as necessary to satisfy the requirement of Specification 3.6.1.4.

1. With one or more of the containment isolation valve(s) inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and either:
   a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or
   b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or
   c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or
   d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.
2. With one required containment purge supply and/or exhaust isolation valve open, close the open valve(s) within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1 DELETED

4.6.3.2 Each containment isolation valve shall be demonstrated OPERABLE during the COLD SHUTDOWN or REFUELING MODE at least once per 18 months by:

a. Verifying that on a Phase A containment isolation test signal, each Phase A isolation valve actuates to its isolation position.

b. Verifying that on a Phase B containment isolation test signal, each Phase B isolation valve actuates to its isolation position.

c. NOT USED

d. Verifying that on a Containment Purge and Pressure-Vacuum Relief isolation test signal, each required Purge and each Pressure-Vacuum Relief valve actuates to its isolation position.

e. Verifying that the Containment Pressure-Vacuum Relief Isolation valves are limited to ≤ 60° opening angle.

4.6.3.3 At least once per 18 months, verify that on a main steam isolation test signal, each main steam isolation valve actuates to its isolation position.

4.6.3.4 The isolation time of each power operated or automatic containment isolation valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.3.5 Each required containment purge isolation valve shall be demonstrated OPERABLE within 24 hours after each closing of the valve, except when the valve is being used for multiple cyclings, then at least once per 72 hours, by verifying that when the measured leakage rate is added to the leakage rates determined pursuant to Specification 4.6.1.2.b for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60La.

4.6.3.6 A pressure drop test to identify excessive degradation of resilient valve seals shall be conducted on the:

a. Required Containment Purge Supply and Exhaust Isolation Valves at least once per 6 months.

b. Deleted.

4.6.3.7 The required containment purge supply and exhaust isolation valves shall be determined closed at least once per 31 days.

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3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves (MSSVs) associated with each steam generator shall be OPERABLE with lift settings as specified in Table 3.7-4.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one or two main steam line code safety valves inoperable in one or more steam generators, operation in Modes 1, 2 and 3 may proceed provided, that within 4 hours, either the inoperable valve is restored to OPERABLE status or reduce power to less than or equal to the applicable percent of RATED THERMAL POWER per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With three main steam line code safety valves inoperable in one or more steam generators, operation in Modes 1, 2 and 3 may proceed provided, that within 4 hours, either the inoperable valves are restored to OPERABLE status or reduce power to less than or equal to the applicable percent of RATED THERMAL POWER per Table 3.7-1 and within 36 hours, reduce the Power Range Neutron Flux High trip setpoint to less than or equal to the RATED THERMAL POWER per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify each required MSSV lift setpoint per Table 3.7-4. No additional Surveillance Requirements other than those required by Specification 4.0.5.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER WITH INOPERABLE
STEAM LINE SAFETY VALVES

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Power* (Percent of RATED THERMAL POWER)
1	87
2	59
3	39

* The values do not provide any allowance for calorimetric error.

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TABLE 3.7-4

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER	Loop A	Loop B	Loop C	Loop D	LIFT SETTING (± 3%)*	ORIFICE SIZE (sq. inches)
a.	21MS11	22MS11	23MS11	24MS11	1125 psig	16.0
b.	21MS12	22MS12	23MS12	24MS12	1120 psig	16.0
c.	21MS13	22MS13	23MS13	24MS13	1110 psig	16.0
d.	21MS14	22MS14	23MS14	24MS14	1100 psig	16.0
e.	21MS15	22MS15	23MS15	24MS15	1070 psig	16.0

* Following testing the lift setting shall be reset to within ± 1%.

PLANT SYSTEMS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated manual activation switches in the control room and flow paths shall be OPERABLE with:

a. Two feedwater pumps, each capable of being powered from separate vital busses, and

b. One feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective action to restore at least one auxiliary feedwater pump to OPERABLE status as soon as possible.

d. LCO 3.0.4.b is not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying that each non-automatic valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

2. Verify the manual maintenance valves in the flow path to each steam generator are locked open.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days on a STAGGERED TEST BASIS by:

1. Verify that the developed head of each motor driven pump at the flow test point is greater than or equal to the required developed head.

2. Verify that the developed head of the steam driven pump at the flow test point is greater than or equal to the required developed head when the steam generator pressure is >680 psig. The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 24 hours after secondary side pressure is greater than 680 psig.

c. At least once per 18 months by:

1. Verifying that each auxiliary feedwater automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

2. Verifying that each auxiliary feedwater pump starts automatically on an actual or simulated actuation signal.

The provisions of Specification 4.0.4 are not applicable to the turbine driven auxiliary feedwater pump, provided the surveillance is performed within 24 hours after the secondary steam generator pressure is greater than 680 psig.

AUXILIARY FEED STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The auxiliary feed storage tank (AFST) shall be OPERABLE with a contained volume of at least 200,000 gallons of water.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the auxiliary feed storage tank inoperable, within 4 hours either:

a. Restore the AFST to OPERABLE status or be in HOT SHUTDOWN within the next 12 hours, or

b. Demonstrate the OPERABILITY of a demineralized water or a fire protection/domestic water storage tank as a backup supply to the auxiliary feedwater pumps and restore the auxiliary feed storage tank to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3.1 The auxiliary feed storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level is within its limits when the tank is the supply source for the auxiliary feedwater pumps.

4.7.1.3.2 A demineralized water storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the tank contains greater than or equal to 200,000 gallons of water and by verifying proper alignment of valves for taking suction from this tank when it is the supply source for the auxiliary feedwater pumps.

4.7.1.3.3 A fire protection/domestic water storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the tank contains greater than or equal to 200,000 gallons of water and by verifying proper alignment of valves for taking suction from this tank when it is the supply source for the auxiliary feedwater pumps.

4.7.1.3.4 The Service Water System shall be demonstrated capable of providing a water supply to the Auxiliary Feedwater System at least once per 12 months by verifying that the required spool-piece is on-site.

ACTIVITY

LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the secondary coolant system shall be less than or equal to 0.10 µCi/gram DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the specific activity of the secondary coolant system greater than 0.10 µCi/gram DOSE EQUIVALENT I-131, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the secondary coolant system shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-2.

TABLE 4.7-2

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY
SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY
1. Gross Activity Determination	At least once per 72 hours
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	a. 1 per 31 days, whenever the gross activity determination indicates iodine concentrations greater than 10% of the allowable limit. b. 1 per 6 months, whenever the gross activity determination indicates iodine concentrations below 10% of the allowable limit.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.5 Each main steam line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

MODES 1 - With one main steam line isolation valve inoperable, POWER OPERATION may continue provided the inoperable valve is either restored to OPERABLE status or closed within 4 hours;

Otherwise, be in MODE 2 within the next 6 hours.

MODES 2 - and 3 With one or more main steam line isolation valve(s) inoperable,subsequent operation in MODES 2 or 3 may proceed provided;

a. The isolation valve(s) is (are) maintained closed, and

b. The isolation valve(s) is (are) verified closed once per 7 days.

Otherwise, be in MODE 3, HOT STANDBY, within the next 6 hours, and MODE 4, HOT SHUTDOWN, within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.5 Each main steam line isolation valve shall be demonstrated OPERABLE by verifying full closure within 5 seconds when tested pursuant to Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

LIMITING CONDITION FOR OPERATION

3.7.2 The temperatures of both the primary and secondary coolants in the steam generators shall be greater than 70°F when the pressure of either coolant in the steam generator is greater than 200 psig.

APPLICABILITY: At all times.

ACTION:

With the requirements of the above specification not satisfied:

a. Reduce the steam generator pressure of the applicable side to less than or equal to 200 psig within 30 minutes, and

b. Perform an engineering evaluation to determine the effect of the overpressurization on the structural integrity of the steam generator. Determine that the steam generator remains acceptable for continued operation prior to increasing its temperatures above 200°F.

SURVEILLANCE REQUIREMENTS

4.7.2 The pressure in each side of the steam generator shall be determined to be less than 200 psig at least once per hour when the temperature of either the primary or secondary coolant is less than 70°F.

PLANT SYSTEMS

3/4.7.3 COMPONENT COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 At least two independent component cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one component cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.*

SURVEILLANCE REQUIREMENTS

4.7.3 At least two component cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

*The time for completion of repairs to number 22 component cooling water heat exchanger shall be extended from 0700 hours on November 23, 1982 to 1300 hours on November 23, 1982. If repairs are not completed by that time, the unit shall be placed in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

3/4.7.4 SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least two independent service water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one service water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4 At least two service water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety related equipment actuates to its correct position on Safeguards Initiation signal.

3/4.7.5 FLOOD PROTECTION

LIMITING CONDITION FOR OPERATION

3.7.5 Flood protection shall be provided for all safety related systems, components and structures when the water level of the Delaware River exceeds 10.5' Mean Sea Level USGS datum, at the service water intake structure.

APPLICABILITY: At all times.

ACTION:

a. With the water level at the service water intake structure above elevation 10.5' Mean Sea Level USGS datum, close all watertight doors within 2 hours.

b. With the water level at the service water intake structure above elevation 11.5' Mean Sea Level USGS datum, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.5 The water level at the service water intake structure shall be determined to be within the limits by:

a. Measurement at least once per 24 hours when the water level is below elevation 10.5' Mean Sea Level USGS datum, and

b. Measurement at least once per 2 hours when the water level is equal to or above elevation 10.5' Mean Sea Level USGS datum.

3/4.7.6 CONTROL ROOM EMERGENCY AIR CONDITIONING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6 The common control room emergency air conditioning system (CREACS)* shall be OPERABLE with:

a. Two independent air conditioning filtration trains (one from each unit) consisting of:

1. Two fans and associated outlet dampers,
2. One cooling coil,
3. One charcoal adsorber and HEPA filter array,
4. Return air isolation damper.

b. All other automatic dampers required for operation in the pressurization or recirculation modes.

c. The control room envelope intact.

APPLICABILITY: ALL MODES and during movement of irradiated fuel assemblies.

ACTION: MODES 1, 2, 3, and 4

a. With one filtration train inoperable, align CREACS for single filtration train operation within 4 hours, and restore the inoperable filtration train to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With CREACS aligned for single filtration train operation and with one of the two remaining fans or associated outlet damper inoperable, restore the inoperable fan or damper to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With the Control Room Envelope inoperable, restore the Control Room Envelope to OPERABLE status within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With one or both series isolation damper(s) on a normal Control Area Air Conditioning System (CAACS) outside air intake or exhaust duct inoperable, close the affected duct within 4 hours by use of at least one isolation damper secured in the closed position or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. (Refer to ACTION 28 of Table 3.3-6.)

*The CREACS is a shared system with Salem Unit 1

e. With one or both isolation damper(s) on an outside emergency air conditioning air intake duct inoperable, close the affected duct within 4 hours by use of at least one isolation damper secured in the closed position and restore the damper(s) to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

f. With any isolation damper between the normal CAACS and the CREACS inoperable, secure the damper in the closed position within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

MODES 5 and 6 or during movement of irradiated fuel assemblies

a. With one filtration train inoperable, align CREACS for single filtration train operation within 4 hours, or suspend movement of irradiated fuel assemblies.

b. With CREACS aligned for single filtration train operation with one of the two remaining fans or associated outlet damper inoperable, restore the fan or damper to OPERABLE status within 72 hours, or suspend movement of irradiated fuel assemblies.

c. With two filtration trains inoperable, immediately suspend movement of irradiated fuel assemblies.

d. With the Control Room Envelope inoperable, immediately suspend movement of irradiated fuel assemblies.

e. With one or both series isolation damper(s) on a normal CAACS outside air intake or exhaust duct inoperable, immediately suspend movement of irradiated fuel assemblies until the affected duct is closed by use of at least one isolation damper secured in the closed position. (Refer to ACTION 28 of Table 3.3-6.)

f. With one or both series isolation damper(s) on an outside emergency air conditioning air intake duct inoperable, immediately suspend movement of irradiated fuel assemblies until the affected duct is closed by use of at least one isolation damper secured in the closed position. To resume movement of irradiated fuel assemblies, at least one emergency air intake duct must be operable on each unit.

g. With any isolation damper between the CAACS and the CREACS inoperable, immediately suspend movement of irradiated fuel assemblies until the damper is closed and secured in the closed position.

SURVEILLANCE REQUIREMENTS

4.7.6.1 The control room emergency air conditioning system shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating flow through the HEPA filter and charcoal adsorber train(s) and verifying that the train(s) operates with each fan operating for at least 15 minutes.

b. At least once per 18 months or prior to return to service (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the system, by:

1. Verifying that the charcoal adsorbers remove $\geq$ 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

2. Verifying that the HEPA filter banks remove $\geq$ 99% of the DOP when they are tested in-place while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

3. Verifying within 31 days after removal from the CREACS unit, that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal from the CREACS unit, that a laboratory analysis of a representative carbon sample, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows a methyl iodide penetration less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

d. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filter and charcoal adsorber bank is $\leq$ 3.5 inches Water Gauge while operating the ventilation system at a flow rate of 8000 cfm ± 10%.

2. Verifying that on a safety injection test signal or control room intake high radiation test signal, the system automatically actuates in the pressurization mode by opening the outside air supply and diverting air flow through the HEPA filter and charcoal adsorber bank.

3. Verifying that the system can maintain the control room at a positive pressure $\geq$ 1/8" water gauge relative to the adjacent areas during system operation with makeup air being supplied through the HEPA filters and charcoal adsorbers at the design makeup flow rate of $\leq$ 2200 cfm.

SURVEILLANCE REQUIREMENTS (Continued)

4. Verifying that on a manual actuation signal, the system will actuate to the required pressurization or recirculation operating mode.

5. **Verify each CREACS train has the capability to remove the assumed heat load.**

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place while operating the filter system at a flow rate of 8000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove ≥ 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the filter system at a flow rate of 8000 cfm ± 10%.

PLANT SYSTEMS

3/4.7.7 AUXILIARY BUILDING VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7 At least two supply fans, and three exhaust fans shall be OPERABLE(*) to maintain the Auxiliary Building at slightly negative pressure.

---------------------------------NOTE---------------------------------

The intermittent opening of the Auxiliary Building pressure boundary causing a loss of negative pressure may be performed under administrative controls.

APPLICABILITY: At all times.

ACTION:

Modes 1 thru 4

a) With one supply fan and/or one exhaust fan inoperable, restore the fan(s) to OPERABLE status within 14 days or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b) With two supply and/or two exhaust fans inoperable restore at least one inoperable supply and two exhaust fans to operable status within 24 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c) With the Auxiliary Building pressure not maintained slightly negative, restore the building to slightly negative pressure within the next 4 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

During CORE ALTERATIONS

d) With the Auxiliary Building pressure not maintained slightly negative, restore the Auxiliary Building to slightly negative pressure within the next 4 hours or suspend all operations involving CORE ALTERATIONS.

At all times

e) With the Auxiliary Building pressure not maintained slightly negative, suspend all operations involving radioactive gaseous releases via the Auxiliary Building immediately.

(*) One of the supply fans may be considered OPERABLE with its auto start circuit administratively controlled (removed form service) to prevent more than one supply fan from operating at any time.

4.7.7 The above required Auxiliary Building Ventilation System shall be demonstrated OPERABLE:

a) At least once per 12 hours by verifying negative pressure in the Auxiliary Building.

b) At least once per 31 days by starting each fan, from the control room, each fan operates for at least 15 minutes.

c) At least once per 18 months by verifying that the system starts following a Safety Injection Test Signal.

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3/4.7.8 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.8 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limits, immediately withdraw the sealed source from use and:

   1. Either decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.8.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.8.2 Test Frequencies - Each category of sealed sources (excluding startup sources and fission detectors previously subjected to core flux) shall be tested at the frequency described below.

a. Sources in use - At least once per six months for all sealed sources containing radioactive materials:

SURVEILLANCE REQUIREMENTS (Continued)

1. With a half-life greater than 30 days (excluding Hydrogen 3), and

2. In any form other than gas.

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux and following repair or maintenance to the source or detector.

4.7.8.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

PLANT SYSTEMS

3/4.7.9 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.9 All snubbers shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4. (MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES).

ACTION:

With one or more snubbers inoperable, within 72 hours, replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.9c on the supported component or declare the supported system inoperable and follow appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.9 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Visual Inspection

All snubbers shall be categorized into two groups: those accessible and those inaccessible during reactor operation. The visual inspection interval for each category of snubbers shall be determined based upon the criteria provided in Table 4.7-3.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are secure, and (3) in those locations where snubber movement can be manually induced without disconnnecting the snubber, that the snubber has freedom of movement and is not frozen up. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, providing that (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specification 4.7.9d or 4.7.9e as applicable. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable and cannot be determined OPERABLE via functional testing for the purpose of establishing the next visual inspection interval. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

c. Functional Tests

At least once per 18 months during shutdown, a representative sample of 10% of the total of each type of snubber in use in the plant shall be functionally tested either in place or in a bench test. For each type of snubber that does not meet the functional test acceptance criteria of Specification 4.7.9d or 4.7.9e, an additional 10% of that type of snubber shall be functionally tested.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle

2. Snubbers within five feet of heavy equipment (valve, pump, turbine, motor, etc.)

3. Snubbers within ten feet of the discharge from a safety relief valve

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber (if it is repaired and installed in another position) and the spare snubber shall be retested. Test results of these snubbers may not be included for the re-sampling.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

For the snubber(s) found inoperable, an engineering evaluation shall be performed on the components which are supported by the snubber(s). The purpose of this engineering evaluation shall be to determine if the components supported by the snubber(s) were adversely affected by the inoperability of the snubber(s) in order to ensure that the supported component remains capable of meeting the designed service.

d. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

e. Mechanical Snubbers Functional Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

f. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.m.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records.

TABLE 4.7-3

SNUBBER VISUAL INSPECTION INTERVAL

Population[1,2] /Category	Number of Unacceptable Snubbers: Column A[3,6] Extend Interval	Column B[4,6] Repeat Interval	Column C[5,6] Reduce Interval
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8

Notes:

1. The next visual inspection interval for the population of a snubber category shall be determined based upon the most recent inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. This decision shall be made and documented before any inspection and used as the basis upon which to determine the next inspection interval for that category.

2. Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Where the limit for unacceptable snubbers in Columns A, B, or C is determined by interpolation and includes a fractional value, the limit may be reduced to the next lower integer.

3. If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

4. If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the current interval.

5. If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the current interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is:

$$I_1 = I_0 - I_0 * {}^1/_3 * \frac{U - B}{C - B}$$

where:

I_1	=	next inspection interval
I_0	=	current inspection interval
U	=	number of unacceptable snubbers found during the previous inspection interval
B	=	number in Column B
C	=	number in Column C

6. The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

3/4.7.10 CHILLED WATER SYSTEM - AUXILIARY BUILDING SUBSYSTEM

LIMITING CONDITION FOR OPERATION

3.7.10 The chilled water system loop which services the safety-related loads in the Auxiliary Building shall be OPERABLE with:

a. Three OPERABLE chillers

b. Two OPERABLE chilled water pumps

APPLICABILITY: ALL MODES and during movement of irradiated fuel assemblies.

ACTION: MODES 1, 2, 3, and 4

a. With one chiller inoperable:

1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

2. Restore the chiller to OPERABLE status within 14 days or;

3. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With two chillers inoperable:

1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

2. Align the control room emergency air conditioning system (CREACs) for single filtration operation using the Salem Unit 1 train within 4 hours and;

3. Restore at least one chiller to OPERABLE status within 72 hours or;

4. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one chilled water pump inoperable, restore the chilled water pump to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

LIMITING CONDITION FOR OPERATION

ACTION: MODES 5 and 6 or during movement of irradiated fuel assemblies.*

a. With one chiller inoperable:

1. Remove the appropriate non-essential heat loads from the Chilled Water System within 4 hours and;

2. Restore the chiller to OPERABLE status within 14 days or;

3. Suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

b. With two chillers inoperable:

1. Remove the appropriate non-essential heat loads from the chilled water system within 4 hours and;

2. Align the control room emergency air conditioning system (CREACs) for single filtration operation using the Salem Unit 1 train within 4 hours and;

3. Restore at least one chiller to OPERABLE status within 72 hours or;

4. Suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

c. With one chilled water pump inoperable, restore the chilled water pump to OPERABLE status within 7 days or suspend CORE ALTERATIONS and movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.7.10 The chilled water loop which services the safety-related loads in the Auxiliary Building shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each manual valve in the chilled water system flow path servicing safety related components that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months, by verifying that each automatic valve actuates to its correct position on a Safeguards Initiation signal.

c. At least once per 92 days by verifying that each chillers starts and runs.

* During Modes 5 and 6 and during movement of irradiated fuel assemblies, chilled water components are not considered to be inoperable solely on the basis that the backup emergency power source, diesel generator, is inoperable.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.7.11 The fuel storage pool boron concentration shall be ≥ 800 ppm

APPLICABILITY: When fuel assemblies are stored in the fuel storage pool and a fuel storage pool verification has not been performed since the last movement of fuel assemblies in the fuel storage pool.

ACTION:

With fuel storage pool boron concentration not within limit:

a. Immediately suspend movement of fuel assemblies in the fuel storage pool and

b. Initiate action to:

   1. immediately restore fuel storage pool boron concentration to within limit or

   2. immediately perform a fuel storage pool verification.

c. The provisions of Specification 3.0.3 is not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11 Verify the fuel storage pool boron concentration is within limit every 7 days.

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL

LIMITING CONDITION FOR OPERATION

3.7.12 The combination of initial enrichment, burnup, and Integral Fuel Burnable Absorber (IFBA) of each fuel assembly stored in Region 1 or Region 2, shall be within the acceptable limits described in the surveillance requirements below.

APPLICABILITY: When any fuel assembly is stored in Region 1 or Region 2 of the spent fuel storage pool.

ACTION:

If the requirements of the LCO are not met:

a. Immediately verify the fuel storage boron concentration meets the requirements of TS 3.7.11 and

b. Immediately initiate action to move the non-complying fuel assembly to a location that complies with the surveillance requirements.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.12.1 Prior to storing fuel assemblies in Region 1, verify by administrative means that the fuel assemblies meet one of the following storage constraints:

d. Unirradiated fuel assemblies with a maximum enrichment of 4.25 wt% U-235 have unrestricted storage.

e. Unirradiated fuel assemblies with enrichments greater than 4.25 wt% U-235 and less than or equal to 5.0 wt% U-235, that do not contain IFBA pins, may only be stored in the peripheral cells facing the concrete wall.

f. Unirradiated fuel assemblies with enrichments (E) greater than 4.25 wt% U-235 and less than or equal to 5.0 wt% U-235, which contain a minimum number of IFBA pins have unrestricted storage. This minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold-down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5x), determined by the equation below:

$$N = 42.67\ (E - 4.25)$$

d. Irradiated fuel assemblies with enrichments (E) greater than 4.25 wt% U-235 and less than or equal to 5.0 wt%, that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -26.212 + 6.1677E$$

4.7.12.2 Prior to storing fuel assemblies in Region 2, verify by administrative means that the fuel assemblies meet one of the following storage constraints:

a. Unirradiated fuel assemblies with a maximum enrichment of 5.0 wt% U-235 may be stored in a checkerboard pattern with intermediate cells containing only water or non-fissile bearing material.

b. Unirradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 may be stored in the central cell of any 3x3 array of cells provided the surrounding eight cells are empty or contain fuel assemblies that have attained the minimum burnup (BU) as determined by the equation below.

$$BU\ (MWD/kg\ U) = -15.48 + 17.80E - 0.7038E^2$$

In this configuration, none of the nine cells in any 3x3 array shall be common to cells in any other similar 3x3 array. Along the rack periphery, the concrete wall is equivalent to 3 outer cells in a 3x3 array.

c. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 that have attained the minimum burnup (BU) as determined by the equation below, have unrestricted storage.

$$BU\ (MWD/kg\ U) = -32.06 + 25.21E - 3.723E^2 + 0.3535E^3$$

d. Irradiated fuel assemblies with a maximum enrichment (E) of 5.0 wt% U-235 that have attained the minimum burnup (BU) as determined by the equation below, may be stored in a peripheral cell facing the concrete wall.

$$BU\ (MWD/kg\ U) = -25.56 + 15.14E - 0.602E^2$$

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent A.C. circuits between the offsite transmission network and the onsite Class 1E distribution system (vital bus system), and

b. Three separate and independent diesel generators with:

1. Separate day tanks containing a minimum volume of 130 gallons of fuel, and

2. A common fuel storage system consisting of two storage tanks, each containing a minimum volume of 23,000 gallons of fuel, and two fuel transfer pumps.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With an independent A.C. circuit of the above required A.C. electrical power sources inoperable:

1. Demonstrate the OPERABILITY of the remaining independent A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; and

2. Within 24 hours, declare required systems or components with no offsite power available inoperable when a redundant required system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

3. Restore the inoperable independent A.C. circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of the above required A.C. electrical power sources inoperable:

1. Demonstrate the OPERABILITY of the independent A.C. circuits by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and

2. Within 4 hours, declare required systems or components supported by the inoperable diesel generator inoperable when a required redundant system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

ACTION (Continued)

3. Determine the two remaining OPERABLE diesel generators are not inoperable due to common cause failure or perform Surveillance Requirement 4.8.1.1.2.a.2 within 24 hours. If the diesel generator is inoperable for preventive maintenance, the two remaining OPERABLE diesel generators need not be tested nor the OPERABILITY evaluated; and

4. In any case, restore the inoperable diesel generator to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one independent A.C. circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining independent A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; demonstrate the OPERABILITY of the remaining OPERABLE diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.2 within 8 hours; restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore at least two independent A.C. circuits and three diesel generators to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With two of the above required independent A.C. circuits inoperable:

1. Demonstrate the OPERABILITY of three diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.2 within 8 hours, unless the diesel generators are already operating; and

2. Within 12 hours, declare required systems or components supported by the inoperable offsite circuits inoperable when a required redundant system or component is inoperable, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

3. Restore at least one of the inoperable independent A.C. circuits to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours; and

4. With only one of the independent A.C. circuits OPERABLE, restore the other independent A.C. circuit to OPERABLE status within 72 hours from time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION (Continued)

e. With two or more of the above required diesel generators inoperable, demonstrate the OPERABILITY of two independent A.C. circuits by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; restore at least two of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore three diesel generators to OPERABLE status within 72 hours from time of initial loss or be in least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

f. With one of the above required fuel transfer pumps inoperable, either restore it to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

g. With one of the above required fuel storage tanks inoperable, either restore it to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

h. LCO 3.0.4.b is not applicable to DGs.

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SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Two physically independent A.C. circuits between the offsite transmission network and the onsite Class 1E distribution system (vital bus system) shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring (manually and automatically) vital bus supply from one 13/4 kv transformer to the other 13/4 kv transformer.

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by:

 1. Verifying the fuel level in its day tank.

 2. Verifying the diesel generator starts from standby conditions* and achieves $\geq$ 3910 volts and $\geq$ 58.8 Hz in $\leq$ 13 seconds, and subsequently achieves steady state voltage of $\geq$ 3910 and $\leq$ 4400 volts and frequency of 60 ± 1.2 Hz.

    Subsequently, verifying the generator is synchronized with voltage maintained $\geq$ 3910 and $\leq$ 4580 volts, gradually loaded to 2340-2600 kw**, and operates at a load of 2340-2600 kw for greater than or equal to 60 minutes.

 3. Verifying the diesel generator is aligned to provide standby power to the associated vital bus.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day tanks.

c. At least once per 6 months by verifying the diesel generator starts from standby conditions* and achieves $\geq$ 3910 volts and $\geq$ 58.8 Hz in $\leq$ 13 seconds, and subsequently achieves steady state voltage of $\geq$ 3910 and $\leq$ 4400 volts and frequency of 60 ± 1.2 Hz.

   The generator shall be synchronized to its emergency bus with voltage maintained $\geq$ 3910 and $\leq$ 4580 volts, loaded to 2340-2600** kw in less than or equal to 60 seconds, and operate at a load of 2340-2600 kw for at least 60 minutes.

   This test, if it is performed so it coincides with the testing required by Surveillance Requirement 4.8.1.1.2.a.2, may also serve to concurrently meet those requirements.

d. At least once per 18 months during shutdown by:

1. DELETED

2. Verifying that, on rejection of a load greater than or equal to 820 kw, the voltage and frequency are restored to ≥ 3910 and ≤ 4400 volts and 60 ± 1.2 Hz within 4 seconds, and subsequently achieves a steady state frequency of ≥ 58.8 and ≤ 60.5 Hz.

3. Simulating a loss of offsite power by itself, and:

   a) Verifying de-energization of the vital bus and load shedding from the vital bus.

   b) Verifying the diesel starts on the auto-start signal*, energizes the vital bus with permanently connected loads within 13 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization of these loads, the steady state voltage and frequency of the vital bus shall be maintained at ≥ 3910 and ≤ 4400 volts and ≥ 58.8 and ≤ 60.5 Hz during this test.

4. Verifying that on an ESF actuation test signal without loss of offsite power the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes*. The diesel generator shall achieve ≥ 3910 volts and ≥ 58.8 Hz in ≤ 13 seconds, and subsequently achieves steady state voltage of ≥ 3910 and ≤ 4400 volts and frequency of ≥ 58.8 and ≤ 60.5 Hz.

5. Deleted

6. Simulating a loss of offsite power in conjunction with an ESF actuation test signal, and

   a) Verifying de-energization of the vital bus and load shedding from the vital bus.

   b) Verifying the diesel starts on the auto-start signal*, energizes the vital bus with permanently connected loads within 13 seconds, energizes the auto-connected emergency (accident) loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization of these loads, the steady state voltage and frequency of the vital bus shall be maintained at ≥ 3910 and ≤ 4400 volts and ≥ 58.8 and ≤ 60.5 Hz during this test.

c) Verifying that all nonessential automatic diesel generator trips (i.e., other than engine overspeed, lube oil pressure low, 4 KV Bus differential and generator differential) are automatically bypassed upon loss of voltage on the vital bus concurrent with a safety injection actuation signal.

7. Deleted

8. Verifying that the auto-connected loads to each diesel generator do not exceed the two hour rating of 2860 kw.

9. Verifying that with the diesel generator operating in a test mode (connected to its bus), a simulated safety injection signal overrides the test mode by (1) returning the diesel generator to standby operation and (2) automatically energizing the emergency loads with offsite power.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously*, during shutdown, and verifying that all diesel generators accelerate to at least 58.8 Hz in less than or equal to 13 seconds.

f. At least once per 18 months, the following test shall be performed within 5 minutes of diesel shutdown after the diesel has operated for at least two hours at 2340-2600 kw**:

Verifying the diesel generator starts and achieves ≥ 3910 volts and ≥ 58.8 Hz in ≤ 13 seconds, and subsequently achieves steady state voltage of ≥ 3910 and ≤ 4400 volts and frequency of 60 ± 1.2 Hz.

g. At least once per 18 months verifying the diesel generator operates for at least 24 hours*. During the first 2 hours of this test, the diesel generators shall be loaded to 2760-2860 Kw**. During the remaining 22 hours of this test, the diesel generator shall be loaded to 2500-2600 Kw**. The steady state voltage and frequency shall be maintained at ≥ 3910 and ≤ 4580 volts and 60 ± 1.2 Hz during this test.

4.8.1.1.3 The diesel fuel oil storage and transfer system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the level in each of the above required fuel storage tanks.

2. Verifying that both fuel transfer pumps can be started and transfer fuel from the fuel storage tanks to the day tanks.

b. At least once per 92 days by verifying that a sample of diesel fuel from each of the above required fuel storage tanks is within the acceptable limits specified in Table 1 of ASTM D975-77 when checked for viscosity, water and sediment.

4.8.1.1.4 Reports - NOT USED

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* Surveillance testing may be conducted in accordance with the manufacturer's recommendations regarding engine prelube, warm-up and loading (unless loading times are specified in the individual Surveillance Requirements).

** This band is meant as guidance to preclude routine exceedances of the diesel generator manufacturer's design ratings. Loads in excess of this band for special testing or momentary variations due to changing bus loads shall not invalidate the test.

TABLE 4.8-1

DIESEL GENERATOR TEST SCHEDULE

NOT USED

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system (vital bus system), and

b. Two separate and independent diesel generators with:

   1. Separate day tanks containing a minimum volume of 130 gallons of fuel, and

   2. A common fuel storage system containing a minimum volume of 23,000 gallons of fuel, and

   3. A fuel transfer pump.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

a. With one of the above minimum required A.C. electrical power sources not OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, movement of irradiated fuel, and positive reactivity changes until the minimum required A.C. electrical power sources are restored to OPERABLE status.

b. With two of the required diesel generators not OPERABLE, suspend all operations involving CORE ALTERATIONS, movement of irradiated fuel, and all operations involving positive reactivity additions, and immediately initiate action to restore one required DG to OPERABLE status.

SURVEILLANCE REQUIREMENTS

---------------------------------------NOTE---------------------------------------
The following surveillances are not required to be performed to maintain operability during Modes 5 and 6. These surveillances are: 4.8.1.1.1.b, 4.8.1.1.2.d.2, 4.8.1.1.2.d.3, 4.8.1.1.2.d.4, 4.8.1.1.2.d.6, 4.8.1.1.2.d.9, 4.8.1.1.2.e, 4.8.1.1.2.f, and 4.8.1.1.2.g.

4.8.1.2 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Surveillance Requirements of 4.8.1.1.1, 4.8.1.1.2, 4.8.1.1.3 (except for requirement 4.8.1.1.3.a.2) and 4.8.1.1.4.

ELECTRICAL POWER SYSTEMS

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A. C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generators:

4 kvolt	Vital Bus # 2A	
4 kvolt	Vital Bus # 2B	
4 kvolt	Vital Bus # 2C	
460 volt	Vital Bus # 2A and associated control centers	
460 volt	Vital Bus # 2B and associated control centers	
460 volt	Vital Bus # 2C and associated control centers	
230 volt	Vital Bus # 2A and associated control centers	
230 volt	Vital Bus # 2B and associated control centers	
230 volt	Vital Bus # 2C and associated control centers	
115 volt	Vital Instrument Bus # 2A and Inverter	*
115 volt	Vital Instrument Bus # 2B and Inverter	*
115 volt	Vital Instrument Bus # 2C and Inverter	*
115 volt	Vital Instrument Bus # 2D and Inverter	*

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With less than the above complement of A.C. busses OPERABLE or energized, restore the inoperable busses to OPERABLE and energized status within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable 2A, 2B, or 2C inverter to OPERABLE and energized status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; restore the inoperable 2D inverter to OPERABLE and energized status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses and inverters shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying correct breaker alignment and indicated voltage on the busses.

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*An inverter may be disconnected from its D.C. source for up to 24 hours for the purpose of performing an equalizing charge on its associated battery bank provided (1) its vital bus is OPERABLE and energized, and (2) the vital busses associated with the other battery banks are OPERABLE and energized.

ELECTRICAL POWER SYSTEMS

A.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, two A.C. electrical bus trains shall be OPERABLE and energized from sources of power other than a diesel generator but aligned to an OPERABLE diesel generator with each train consisting of:

1 - 4 kvolt Vital Bus

1 - 460 volt Vital Bus and associated control centers

1 - 230 volt Vital Bus and associated control centers

1 - 115 volt Instrument Bus energized from its respective inverter connected to its respective D. C. bus train.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of A.C. busses and inverters OPERABLE and energized, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement of irradiated fuel assemblies until the minimum required A.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.2 The specified A.C. busses and inverters shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying correct breaker alignment and indicated voltage on the busses.

125-VOLT D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.3 The following D.C. bus trains shall be OPERABLE and energized:

TRAIN 2A consisting of 125-volt D.C. bus No. 2A, 125-volt D.C. battery No. 2A and battery charger 2A1.

TRAIN 2B consisting of 125-volt D.C. bus No. 2B, 125-volt D.C. battery No. 2B and battery charger 2B1.

TRAIN 2C consisting of 125-volt D.C. bus No. 2C, 125-volt D.C. battery No. 2C and battery charger 2C1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one 125-volt D.C. bus inoperable or not energized, restore the inoperable bus to OPERABLE and energized status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one 125-volt D.C. battery charger inoperable, restore the inoperable charger to OPERABLE status within 2 hours or connect the backup charger for no more than 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one or more 125-volt D.C. batteries with one or more battery cell parameters not within the Category A or B limits of Table 4.8.2.3-1:
   1. Verify within 1 hour, that the electrolyte level and float voltage for the pilot cell meets Table 4.8.2.3-1 Category C limits, and
   2. Verify within 24 hours, that the battery cell parameters of all connected cells meet Table 4.8.2.3-1 Category C limits, and
   3. Restore battery cell parameters to Category A and B limits of Table 4.8.2.3-1 within 31 days, and
   4. If any of the above listed requirements cannot be met, comply with the requirements of action f.

d. With one or more 125-volt D.C. batteries with one or more battery cell parameters not within Table 4.8.2.3-1 Category C values, comply with the requirements of action f.

e. With average electrolyte temperature of representative cells less than 65°F, comply with the requirements of action f.

f. Restore the battery to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

4.8.2.3.1 Each D.C. bus train shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and voltage on the bus.

4.8.2.3.2 Each required 125-volt battery and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

   1. The parameters in Table 4.8.2.3-1 meet Category A limits.

   2. The overall battery voltage is greater than or equal to 125 volts on float charge.

b. At least once per 92 days and once within 24 hours after a battery discharge < 110 V and once within 24 hours after a battery overcharge > 150 V by verifying that the parameters in Table 4.8.2.3-1 meet the Category B limits.

c. At least once per 92 days by verifying that:

   1. There is no visible corrosion at terminals or connectors or the connection resistance is:

      ≤150 micro ohms for inter-cell connections,
      ≤350 micro ohms for inter-rack connections,
      ≤350 micro ohms for inter-tier connections,
      ≤70 micro ohms for field cable terminal connections, and
      ≤2500 micro ohms for the total battery connection

      resistance which includes all inter-cell connections (including bus bars), all inter-rack connections (including cable resistance) all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

   2. The average electrolyte temperature of the representative cells is above 65°F.

d. At least once per 12 months by verifying that:

   1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration.

   2. Remove visible terminal corrosion and verify cell-to-cell and terminal connections are coated with anti-corrosion material.

3. The connection resistance is:
≤150 micro ohms for inter-cell connections,
≤350 micro ohms for inter-rack connections,
≤350 micro ohms for inter-tier connections,
≤70 micro ohms for field cable terminal connections,and
≤2500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-rack connections (including cable resistance) all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

e. At least once per 18 months by verifying that the battery charger will supply at least 170 amperes at 125 volts for at least 4 hours.

f. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

g. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Satisfactory completion of this performance discharge test shall also satisfy the requirements of Specification 4.8.2.3.2.f if the performance discharge test is conducted during a shutdown where that test and the battery service test would both be required.

h. At least once per 12 months, during shutdown, if the battery shows signs of degradation OR has reached 85% of the service life with a capacity less than 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

i. At least once per 24 months, during shutdown, if the battery has reached 85% of the service life with capacity greater than or equal to 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test.

TABLE 4.8.2.3-1

BATTERY CELL PARAMETERS REQUIREMENTS

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE VALUE FOR EACH CONNECTED CELL
Electrolyte Level	>Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark (a)	>Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark (a)	Above top of plates, and not overflowing
Float Voltage	≥2.13 V	≥2.13 V	≥2.07 V
Specific Gravity (b) (c)	≥1.195	≥1.190 AND Average of all connected cells ≥1.200	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charge provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 3 amps when on float charge.

(c) Or battery charging current is < 3 amps when on float charge. This is acceptable only during a maximum of 7 days following a battery recharge.

125-VOLT D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.4 As a minimum, the following D.C. electrical equipment and bus shall be energized and OPERABLE:

2 - 125-volt D.C. busses, and

2 - 125-volt batteries, each with at least one full capacity charger, associated with each of the above D.C. busses.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of D.C. equipment and busses OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement of irradiated fuel assemblies until the minimum required 125Volt D.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.4.1 The above required 125-volt D.C. busses shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and indicated power availability.

4.8.2.4.2 The above required 125-volt batteries and chargers shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.3.2.

28-VOLT D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.5 The following D.C. bus trains shall be energized and OPERABLE:

TRAIN 2A consisting of 28-volt D.C. bus No. 2A, 28-volt D.C. battery No. 2A and battery charger 2A1.

TRAIN 2B consisting of 28-volt D.C. bus No. 2B, 28-volt D.C. battery No. 2B, and battery charger 2B1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one 28-volt D.C. bus inoperable or not energized, restore the inoperable bus to OPERABLE and energized status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one required 28-volt D.C. battery charger inoperable, restore the inoperable charger to OPERABLE status within 2 hours or connect the backup charger for no more than 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one or more 28-volt D.C. batteries with one or more battery cell parameters not within the Category A or B limits of Table 4.8.2.5-1:

   1. Verify within 1 hour, that the electrolyte level and float voltage for the pilot cell meets Table 4.8.2.5-1 Category C limits, and
   2. Verify within 24 hours, that the battery cell parameters of all connected cells meet Table 4.8.2.5-1 Category C limits, and
   3. Restore battery cell parameters to Category A and B limits of Table 4.8.2.5-1 within 31 days, and
   4. If any of the above listed requirements cannot be met, comply with the requirements of action f.

d. With one or more 28-volt D.C. batteries with one or more battery cell parameters not within Table 4.8.2.5-1 Category C values, comply with the requirements of action f.

e. With average electrolyte temperature of representative cells less than 65°F, comply with the requirements of action f.

f. Restore the battery to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

4.8.2.5.1 Each D.C. bus train shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and power availability.

4.8.2.5.2 Each 28-volt battery and above required charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

   1. The parameters in Table 4.8.2.5-1 meet Category A limits.

   2. The overall battery voltage is greater than or equal to 27 volts on float charge.

b. At least once per 92 days and once within 24 hours after a battery discharge < 25.7 V and once within 24 hours after a battery overcharge > 35 V by verifying that the parameters in Table 4.8.2.5-1 meet the Category B limits.

c. At least once per 92 days by verifying that:

   1. There is no visible corrosion at terminals or connectors or the connection resistance is:

      ≤ 50 micro ohms for inter-cell connections,
      ≤ 200 micro ohms for inter-tier connections,
      ≤ 70 micro ohms for field cable terminal connections, and
      ≤ 500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

   2. The average electrolyte temperature of the representative cells is ≥ 65°F.

d. At least once per 12 months by verifying that:

   1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration.

   2. Remove visible terminal corrosion and verify cell-to-cell and terminal connections are coated with anti-corrosion material.

   3. The connection resistance is:

      ≤ 50 micro ohms for inter-cell connections,
      ≤ 200 micro ohms for inter-tier connections,
      ≤ 70 micro ohms for field cable terminal connections, and
      ≤ 500 micro ohms for the total battery connection resistance which includes all inter-cell connections (including bus bars), all inter-tier connections (including cable resistance) and all field terminal connections at the battery.

e. At least once per 18 months by verifying that the battery charger will supply $\geq$ 150 amperes at $\geq$ 28 volts for $\geq$ 4 hours.

f. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

g. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Satisfactory completion of this performance discharge test shall also satisfy the requirements of Specification 4.8.2.5.2.f if the performance discharge test is conducted during a shutdown where that test and the battery service test would both be required.

h. At least once per 12 months, during shutdown, if the battery shows signs of degradation <u>OR</u> has reached 85% of the service life with a capacity less than 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

i. At least once per 24 months, during shutdown, if the battery has reached 85% of the service life with capacity greater than or equal to 100% of manufacturers rating, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test.

TABLE 4.8.2.5-1

BATTERY CELL PARAMETER REQUIREMENTS

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE VALUE FOR EACH CONNECTED CELL
Electrolyte Level	>Minimum level indication mark and ≤ 1/4 inch above maximum level indication mark[a]	>Minimum level indication mark and ≤ 1/4 inch above maximum level indication mark[a]	Above top of plates and not overflowing
Float Voltage	≥2.13 V	≥2.13 V	≥2.07 V
Specific Gravity[b] [c]	≥1.195	≥1.190 AND Average of all Connected cells ≥1.200	Not more than 0.020 below the average of all connected cells AND Average of all connected cells ≥1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charge provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 2 amps when on float charge.

(c) Or battery charging current is < 2 amps when on float charge. This is acceptable only during a maximum of 7 days following a battery recharge.

28-VOLT D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.6 As a minimum, the following D. C. electrical equipment and bus shall be energized and OPERABLE:

1 - 28-volt D.C. bus, and

1 - 28-volt battery and at least one full capacity charger associated with the above D.C. bus.

APPLICABILITY: MODES 5 and 6.
During movement of irradiated fuel assemblies.

ACTION:

With less than the above complement of D.C. equipment and busses OPERABLE, immediately declare the affected required features inoperable, or suspend all operations involving CORE ALTERATIONS, positive reactivity changes, and movement or irradiated fuel assemblies until the minimum required 28Volt D.C. electrical power sources are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.8.2.6.1 The above required 28-volt D.C. bus shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and voltage on the bus.

4.8.2.6.2 The above required 28-volt batteries and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.5.2.

3/4.8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.3.1 All containment penetration conductor overcurrent protective devices required to provide thermal protection of penetrations shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the containment penetration conductor overcurrent protective device(s) inoperable:

a. Restore the protective device(s) to OPERABLE status or de-energize the circuit(s) by tripping either the primary or backup protective device, or racking out or removing the primary or backup device within 72 hours, declare the affected system or component inoperable, and verify the primary or backup protective device to be tripped, or the primary or backup device racked out or removed at least once per 7 days thereafter; or

b. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.3.1 All required containment penetration conductor overcurrent protective devices shall be demonstrated OPERABLE:

a. At least once per 18 months:

   1. For at least one 4.16 KV reactor coolant pump circuit, such that all reactor coolant pump circuits are demonstrated OPERABLE at least once per 72 months, by performance of:

      (a) A CHANNEL CALIBRATION of the associated protective relays, and

      (b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed.

SURVEILLANCE REQUIREMENTS (Continued)

2. By verifying the OPERABILITY of the required molded case and lower voltage circuit breakers, by selecting and functionally testing a representative sample of at least 10% of all the circuit breakers of that type. Circuit breakers selected for functional testing shall be selected on a rotating basis. The functional test shall consist of injecting a current input at the specified setpoint to each selected circuit breaker and verifying that each circuit breaker functions as designed. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during the functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

TABLE 3.8-1

CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

DELETED

3/4.9 REFUELING OPERATIONS

BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of the Reactor Coolant System, the fuel storage pool, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODE 6 (Only applicable to the refueling canal, the fuel storage pool and refueling cavity when connected to the Reactor Coolant System)

ACTION:
With the requirements of the above specification not satisfied, immediately

a. Suspend CORE ALTERATIONS and
b. Suspend positive reactivity additions and
c. Initiate action to restore boron concentration to within limit specified in the COLR.
d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.1 Verify the boron concentration is within the limit of the COLR every 72 hours.

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 As a minimum, two source range neutron flux monitors shall be operating, each with continuous visual indication in the control room and one with audible indication in the containment and control room.

APPLICABILITY: MODE 6.

ACTION:

a. With one of the above required monitors inoperable, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

b. With both of the required monitors inoperable, determine the boron concentration of the reactor coolant system at least once per 12 hours.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.2 Each source range neutron flux monitor shall be demonstrated OPERABLE by performance of:

a. A CHANNEL CHECK at least once per 12 hours, and

b. A CHANNEL FUNCTIONAL TEST at least once per 7 days.

DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.3 The reactor shall be subcritical for at least:

a. 100 hours - Applicable through year 2010.
b. 168 hours

APPLICABILITY: Specification 3.9.3.a - From October 15th through May 15th, during movement of irradiated fuel in the reactor pressure vessel.

Specification 3.9.3.b - From May 16th through October 14th, during movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than the required time, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.3 The reactor shall be determined to have been subcritical as required by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

CONTAINMENT BUILDING PENETRATIONS

LIMITING CONDITION FOR OPERATION

3.9.4 The containment building penetrations shall be in the following status:

a. The equipment hatch inside door is capable of being closed and held in place by a minimum of four bolts, or an equivalent closure device installed and capable of being closed,

b. A minimum of one door in each airlock is capable of being closed

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either:

1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or
2. capable of being closed by the Containment Purge and Pressure-Vacuum Relief Isolation System.

Note: Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During movement of irradiated fuel within the containment.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving movement of irradiated fuel in the containment building. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.4.1 Each of the above required containment building penetrations shall be determined to be either in its required condition or capable of being closed by a manual or automatic containment isolation valve at least once per 7 days.

4.9.4.2 Once per refueling prior to the start of movement of irradiated fuel assemblies within the containment building, verify the capability to install, within 1 hour, the equipment hatch. Applicable only when the equipment hatch is open during movement of irradiated fuel in the containment building.

4.9.4.3 Verify, once per 18 months, each required containment purge isolation valve actuates to the isolation position on a manual actuation signal.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communications shall be maintained between the control room and personnel at the refueling station.

APPLICABILITY: During CORE ALTERATIONS.

ACTION:

When direct communications between the control room and personnel at the refueling station cannot be maintained, suspend all CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communications between the control room and personnel at the refueling station shall be demonstrated within one hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.

MANIPULATOR CRANE OPERABILITY

LIMITING CONDITION FOR OPERATION

3.9.6 The manipulator crane and auxiliary hoist shall be used for movement of control rods or fuel assemblies and shall be OPERABLE with:

a. The manipulator crane used for movement of fuel assemblies having:

1. A minimum capacity of 3250 pounds, and

2. An overload cut off limit less than or equal to 2850 pounds.

b. The auxiliary hoist used for movement of control rods having:

1. A minimum capacity of 700 pounds, and

2. A load indicator which shall be used to prevent lifting loads in excess of 600 pounds.

APPLICABILITY: During movement of control rods or fuel assemblies within the reactor pressure vessel.

ACTION:

With the requirements for crane and/or hoist OPERABILITY not satisfied, suspend use of any inoperable manipulator crane and/or auxiliary hoist from operations involving the movement of control rods and fuel assemblies within the reactor pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.6.1 Each manipulator crane used for movement of fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 3250 pounds and demonstrating an automatic load cut off set at less than or equal to 2850 pounds; this includes the heavy load plus the weight of the crane mast and gripper.

4.9.6.2 Each auxiliary hoist and associated load indicator used for movement of control rods within the reactor pressure vessel shall be demonstrated OPERABLE within 100 hours prior to the start of such operations by performing a load test of at least 700 pounds.

CRANE TRAVEL - FUEL HANDLING AREA

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 2200 pounds shall be prohibited from travel over fuel assemblies in the storage pool.

APPLICABILITY: With fuel assemblies in the storage pool.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 The overload cutoff which prevents crane travel with loads in excess of 2200 pounds over fuel assemblies shall be demonstrated OPERABLE within 7 days prior to crane use and at least once per 7 days thereafter during the crane operation.

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

ALL WATER LEVELS

LIMITING CONDITION FOR OPERATION

3.9.8.1 At least one residual heat removal loop shall be in operation.

APPLICABILITY: MODE 6.

ACTION:

a. With less than one residual heat removal loop in operation, except as provided in b. below, suspend all operations involving an increase in the reactor decay heat load or a reduction in boron concentration of the Reactor Coolant System. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

b. The residual heat removal loop may be removed from operation for up to 1 hour per 8 hour period during the performance of CORE ALTERATIONS in the vicinity of the reactor pressure vessel hot legs.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.1 At least once per 12 hours one RHR loop shall be verified in operation and circulating coolant at a flow rate of:

a. greater than or equal to 1000 gpm, and

b. sufficient to maintain the RCS temperature at less than or equal to 140°F.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent Residual Heat Removal (RHR) loops shall be OPERABLE.*

APPLICABILITY: MODE 6 when water level above the top of the reactor pressure vessel flange is less than 23 feet.

ACTION:

a. With less than the required RHR loops operable, immediately initiate corrective action to return the required RHR loops to OPERABLE status as soon as possible.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.2 The required Residual Heat Removal loops shall be determined OPERABLE per Specification 4.0.5.

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* Systems supporting RHR loop operability may be excepted as follows:

a. The normal or emergency power source may be inoperable.

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3/4.9.10 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.10 At least 23 feet of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During movement of fuel assemblies or control rods within the reactor pressure vessel when either the fuel assemblies being moved or the fuel assemblies seated within the reactor pressure vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving movement of fuel assemblies or control rods within the pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.10 The water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and at least once per 24 hours thereafter during movements of fuel assemblies or control rods.

3/4.9.11 STORAGE POOL WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11 At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the storage pool.

ACTION:

With the requirements of the specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the fuel storage areas and restore water level to within its limit within 4 hours. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.11 The water level in the storage pool shall be determined to be at least its minimum required depth at least once per 7 days when irradiated fuel assemblies are in the fuel storage pool.

3/4.9.12 FUEL HANDLING AREA VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 The Fuel Handling Area Ventilation System shall be OPERABLE with:

a. Two exhaust fans and one supply fan OPERABLE and operating, and

b. Capable of maintaining slightly negative pressure in the Fuel Handling Building.

APPLICABILITY: During movement of irradiated fuel within the Fuel Handling Building

ACTION:

a. With no Fuel Handling Area Ventilation System OPERABLE, suspend all operations involving movement of fuel within the storage pool until the Fuel Handling Area Ventilation System is restored to OPERABLE status.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.12 The above required ventilation system shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the Fuel Handling Building is maintained at a slightly negative pressure with respect to atmospheric pressure.

b. At least once per 31 days by verifying both exhaust fans and one supply fan start and operate for at least 15 minutes, if not operating already.

c. At least once per 18 months by verifying a system flowrate of 19,490 cfm ± 10% during system operation.

3/4.10 SPECIAL TEST EXCEPTIONS

SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.10.1 The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 may be suspended for measurement of control rod worth and shutdown margin provided the reactivity equivalent to at least the highest estimated control rod worth is available for trip insertion from OPERABLE control rod(s).

APPLICABILITY: MODE 2.

ACTION:

a. With any full length control rod not fully inserted and with less than the above reactivity equivalent available for trip insertion, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

b. With all full length control rods inserted and the reactor subcritical by less than the above reactivity equivalent, immediately initiate and continue boration at ≥ 33 gpm of a solution containing ≥ 6,560 ppm boron or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

SURVEILLANCE REQUIREMENTS

4.10.1.1 The position of each full length rod either partially or FULLY WITHDRAWN shall be determined at least once per 2 hours.

4.10.1.2 Each full length rod not fully inserted shall be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position within 24 hours prior to reducing the SHUTDOWN MARGIN to less than the limits of Specification 3.1.1.1.

SPECIAL TEST EXCEPTIONS

GROUP HEIGHT, INSERTION AND POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The group height, insertion and power distribution limits of Specifications 3.1.3.1, 3.1.3.4, 3.1.3.5, 3.2.1, and 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER is maintained less than or equal to 85%# of RATED THERMAL POWER, and

b. The limits of Specifications 3.2.2 and 3.2.3 are maintained and determined at the frequencies specified in Specification 4.10.2.2 below.

APPLICABILITY: MODE 1.

ACTION:

With any of the limits of Specifications 3.2.2 or 3.2.3 being exceeded while the requirements of Specifications 3.1.3.1, 3.1.3.4, 3.1.3.5, 3.2.1 and 3.2.4 are suspended, either:

a. Reduce THERMAL POWER sufficient to satisfy the ACTION requirements of Specifications 3.2.2 and 3.2.3, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined to be less than or equal to 85% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

4.10.2.2 The below listed surveillance requirements shall be performed at least once per 12 hours during PHYSICS TESTS:

a. Surveillances 4.2.2.2 and 4.2.2.3.

b. Surveillances 4.2.3.1 and 4.2.3.2.

See page 3/4 10-3

SURVEILLANCE REQUIREMENTS (Continued)

#A THERMAL POWER limit of 100% of RATED THERMAL POWER is permissible during the Power Coefficient Test and the Load Swing Test Performed as part of the Initial Startup Test Program, provided the following conditions are met:

1. The target axial offset at full Power shall be less negative or equal to -16%.
2. The ΔI value during the Test shall not be more negative than -23% at 90% power and -25% at 80% power.
3. Before initiation of the test, Bank D control group shall be positioned as far out of the core as possible, consistent with minimum differential rod worth requirements, no lower than 190 steps.
4. The limits of Specification 3.1.3.5 shall not be violated.
5. Each of the above tests (Power Coefficient Test and Load Swing Test) shall be performed in less than or equal to 2 hours and thest tests shall be completed prior to exceeding a core average fuel burnup of 3000 MWD/MTU.

SPECIAL TEST EXCEPTIONS

PHYSICS TESTS

LIMITING CONDITION FOR OPERATION

3.10.3 The limitations of Specifications 3.1.1.3, 3.1.1.4, 3.1.3.1, 3.1.3.4 and 3.1.3.5 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER,

b. The reactor trip setpoints on the OPERABLE Intermediate and Power Range Nuclear Channels are set at less than or equal to 25% of RATED THERMAL POWER, and

c. The Reactor Coolant System lowest operating loop temperature (T_{avg}) is greater than or equal to 531°F.

APPLICABILITY: MODE 2.

ACTION:

a. With the THERMAL POWER greater than 5% of RATED THERMAL POWER, immediately open the reactor trip breakers.

b. With a Reactor Coolant System operating loop temperature (T_{avg}) less than 531°F, restore T_{avg} to within its limit within 15 minutes or be in at least HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.10.3.1 The THERMAL POWER shall be determined to be less than or equal to 5% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

4.10.3.2 Each Intermediate and Power Range Channel shall be subjected to a CHANNEL FUNCTIONAL TEST prior to initiating PHYSICS TESTS.

4.10.3.3 The Reactor Coolant System temperature (T_{avg}) shall be determined to be greater than or equal to 531°F at least once per 30 minutes during PHYSICS TESTS.

SPECIAL TEST EXCEPTIONS

NO FLOW TESTS

LIMITING CONDITION FOR OPERATION

3.10.4 The limitations of Specification 3.4.1.1 may be suspended during the performance of startup and PHYSICS TESTS, provided:

a. The THERMAL POWER does not exceed the P-7 Interlock Setpoint, and

b. The Reactor Trip Setpoints on the OPERABLE Intermediate and Power Range Channels are set less than or equal to 25% of RATED THERMAL POWER

APPLICABILITY: During operation below the P-7 Interlock Setpoint.

ACTION:

With the THERMAL POWER greater than the P-7 Interlock Setpoint, immediately open the reactor trip breakers.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The THERMAL POWER shall be determined to be less than P-7 Interlock Setpoint at least once per hour during startup and PHYSICS TESTS.

4.10.4.2 Each Intermediate, Power Range Channel and P-7 Interlock shall be subjected to a CHANNEL FUNCTIONAL TEST prior to initiating startup or PHYSICS TESTS.

3/4.11 RADIOACTIVE EFFLUENTS

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RADIOACTIVE EFFLUENTS

LIQUID HOLDUP TANKS*

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in each outdoor temporary tank shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each outdoor temporary tank shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

* Tanks included in this Specification are those outdoor temporary tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

RADIOACTIVE EFFLUENTS

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RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of oxygen in the waste gas holdup system shall be limited to less than or equal to 2% by volume.

APPLICABILITY: At all times. *

ACTION:

a. With the concentration of oxygen in the waste gas holdup system greater than 2% by volume but less than or equal 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

b. With the concentration of oxygen in the waste gas holdup system greater than 4% by volume immediately suspend all additions of waste gases to the system and reduce the concentration of oxygen to less than or equal to 2% by volume without delay.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5 The concentration of oxygen in the waste gas holdup system shall be determined to be within the above limits by continuously** monitoring the waste gases in the waste gas holdup system with the oxygen monitor. If hydrogen is not measured, the concentration of hydrogen shall be assumed to exceed 4% by volume.

* Not applicable to portions of the Waste Gas System removed from service for maintenance provided that, the portions removed for maintenance are isolated, and purged of hydrogen to less than 4% by volume.

** If the oxygen monitoring instrumentation is inoperable, operation of the waste gas holdup system may continue provided grab samples are collected at least once per 24 hours and analyzed within the following 4 hours.

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Specification 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL MODES or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in a MODE or condition in which the specification no longer applies. It is not intended that the shutdown ACTION requirements be used as an operational convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

The specified time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered a MODE in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown MODE when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or the time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in the COLD SHUTDOWN MODE when a shutdown is required during the POWER MODE of operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE of operation applies. However, if a lower MODE of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other applicable MODE, is not reduced. For example, if HOT STANDBY is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because of the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do not apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these system and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on an ACTION in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications that describe values and parameters (e.g., Containment Air Temperature, Containment Pressure, Moderator Temperature Coefficient), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and

Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 4.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 4.0.1 or SR 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

Specification 3.0.5

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Specification 3.0.6 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of testing required to restore and demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the testing required to restore and demonstrate the operability of the equipment. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the testing required to restore and demonstrate OPERABILITY.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of testing required to restore OPERABILITY of another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of testing required to restore and demonstrate the OPERABILITY of another channel in the same trip system.

Specifications 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that Surveillance Requirements must be met during the OPERATIONAL MODES or other specified conditions in the Applicability for which the requirements of the Limiting Conditions for Operation apply, unless otherwise specified in an individual Surveillance Requirement. This specification is to ensure that surveillances are performed to verify the OPERABILITY of systems and components and that variables are within specified limits.

Failure to meet a Surveillance within the specified Frequency, in accordance with Specification 4.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated Surveillance Requirements have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when either:

a. The systems or components are known to be inoperable, although still meeting the Surveillance Requirements, or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the facility is in an OPERATIONAL MODE or other specified condition for which the requirements of the associated Limiting Condition for Operation do not apply, unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given Surveillance. In this case, the unplanned event may be credited as fulfilling the performance of the Surveillance Requirement. This allowance includes those Surveillances whose performance is normally precluded in a given OPERATIONAL MODE or other specified condition.

Surveillances, including Surveillances invoked by ACTIONS, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2 prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Auxiliary Feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures > 680 psig. However, if other appropriate testing is satisfactorily completed, the AFW system can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

b. High Pressure Safety Injection (HPI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18 month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any

particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable, or an affected variable outside the specified limits, when a Surveillance has not been completed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with TS 3.0.2, and not at the time that the specified frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals,—but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 4.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity. SR 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified frequencies for Surveillances is expected to be an infrequent occurrence. Use of the delay period established by SR 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance.

This risk impact should be managed through the program in place to implement 10 CFR50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable, or the variable is considered outside the specified limits, and the Completion Times of the Required Actions for the applicable LCO begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits, and the Completions Times of the Required Actions for the applicable LCO begins immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the Actions, restores compliance with SR 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

However, in two certain circumstances, failing to meet an SR will not result in SR 4.0.4 restricting a MODE change or other specified condition change:

(1) When a system, subsystem, division, component, device or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 4.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

(2) SR 4.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 4.0.3.

The provisions of SR 4.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 4.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 4.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a. These requirements apply except when relief has been provided in writing by the Commission.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL MODE or

other specified condition takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, that is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.3% $\Delta k/k$ is initially required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR safety analysis assumptions. With T_{avg} less than or equal to 200°F, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% $\Delta k/k$ shutdown margin provides adequate protection.

3/4.1.1.3 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting condition assumed in the accident and transient analyses.

3/4.1.1.3 MODERATOR TEMPERATURE COEFFICIENT (MTC) (Continued)

The MTC values of this specification are applicable to a specific set of plant conditions; accordingly, verification of MTC values at conditions other than those explicitly stated will require extrapolation to those conditions in order to permit an accurate comparison.

The most negative MTC value equivalent to the most positive moderator density coefficient (MDC), was obtained by incrementally correcting the MDC used in the FSAR analysis to nominal operating conditions. These corrections involved: (1) a conversion of the MDC used in the FSAR analysis to its equivalent MTC, based on the rate of change of moderator density with temperature at RATED THERMAL POWER conditions, and (2) subtracting from this value the largest differences in MTC observed between EOL, all rods withdrawn, RATED THERMAL POWER conditions, and those most adverse conditions of moderator temperature and pressure, rod insertion, axial power skewing, and xenon concentration that can occur in normal operation and lead to a significantly more negative EOL MTC at RATED THERMAL POWER. These corrections transformed the MDC value used in the FSAR analysis into the limiting End Of Cycle Life (EOL) MTC value. The 300 ppm surveillance limit MTC value represents a conservative value at a core condition of 300 ppm equilibrium boron concentration that is obtained by correcting the limiting EOL MTC for burnup and born concentration.

The surveillance requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains with its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.1.1.4 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 541°F. This limitation is required to ensure 1) the moderator temperature coefficient is within its analyzed temperature range, 2) the protective instrumentation is within its normal operating range, 3) the P-12 interlock is above its allowable setpoint, 4) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and 5) the reactor pressure vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The boron injection system ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include: 1) borated water sources, 2) charging pumps, 3) separate flow paths, 4) boric acid transfer pumps, and 5) offsite power or an emergency power supply from OPERABLE diesel generators.

With the RCS average temperature ≥ 350°F, a minimum of two boron injection flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable. The boration capability of either flow path is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of 1.3% delta k/k after xenon decay and cooldown to 200°F. The maximum expected boration capability (minimum boration volume) requirement is established to conservatively bound expected operating conditions throughout core operating life. The analysis assumes that the most reactive control rod is not inserted into the core. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires borated water from a boric acid tank in accordance with TS Figure 3.1-2, and additional makeup from either: (1) the second boric acid tank and/or batching, or (2) a maximum of 41,800 gallons of 2,300 ppm borated water from the refueling water storage tank. With the refueling water storage tank as the only borated water source, a maximum of 73,800 gallons of 2,300 ppm borated water is required. However, to be consistent with the ECCS requirements, the RWST is required to have a minimum contained volume of 350,000 gallons during operations in MODES 1, 2, 3 and 4.

The boric acid tanks, pumps, valves, and piping contain a boric acid solution concentration of between 3.75% and 4% by weight. To ensure that the boric acid remains in solution, the tank fluid temperature and the process pipe wall temperatures are monitored to ensure a temperature of 63°F, or above is maintained. The tank fluid and pipe wall temperatures are monitored in the main control room. A 5°F margin is provided to ensure the boron will not precipitate out.

Should ambient temperature decrease below 63°F, the boric acid tank heaters, in conjunction with boric acid pump recirculation, are capable of maintaining the boric acid in the tank and in the pump at or about 63°F. A small amount of boric acid in the flowpath between the boric acid recirculation line and the suction line to the charging pump will precipitate out, but it will not cause flow blockage even with temperatures below 50°F.

With the RCS temperature below 350°F, one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE OPERATIONS and positive reactivity change in the event the single injection system becomes inoperable.

The boron capability required below 200°F is sufficient to provide a SHUTDOWN MARGIN of 1% delta k/k after xenon decay and cooldown from 200°F to 140°F. This condition requires either 2,600 gallons of 6,560 ppm borated water from the boric acid storage tanks or 7,100 gallons of 2,300 ppm borated water from the refueling water storage tank.

The 37,000 gallons limit in the refueling water storage tank for Modes 5 and 6 is based upon 21,210 gallons that is undetectable due to lower tap location, 8,550 gallons for instrument error, 7,100 gallons required for shutdown margin, and an additional 140 gallons due to rounding up.

The limits on contained water volume and boron concentration of the RWST also ensure a pH value of between 7.0 and 10.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The contained water volume limits include allowance for water not available because of discharge line location and other physical characteristics.

The OPERABILITY of one boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) limit the potential effects of rod mis-alignment on associated accident analyses. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. OPERABLE condition for the analog rod position indicators is defined as being capable of indicating rod position to within the allowed rod misalignment relative to the bank demand position for a range of positions. For the Shutdown Banks, and Control Bank A this range is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 and 228 steps withdrawn inclusive. This permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these banks positions in these ranges satisfies all accident analysis assumptions concerning their position. The range for control Bank B is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 160 and 228 steps withdrawn inclusive. For Control Banks C and D the range is defined as the group demand counter indicated position between 0 and 228 steps withdrawn. Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the insertion limits. The full out position will be specifically established for each cycle by the Reload Safety Analysis for that cycle. This position will be within the band established by "FULL WITHDRAWN" and will be administratively controlled. This band is allowable to minimize RCCA wear, pursuant to Information Notice 87-19.

The ACTION statements which permit limited variation from the basic requirements are accompanied by additional restrictions which ensure that the original criteria are met. Mis-alignment of a rod requires measurement of peaking factors or a restriction in THERMAL POWER; either of these restrictions provide assurance of fuel rod integrity during continued operation. The reactivity worth of a mis-aligned rod is limited for the remainder of the fuel cycle to prevent exceeding the assumption used in the accident analysis.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the accident analyses. Measurement with T_{avg} >541°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

Control rod positions and OPERABILITY of the rod position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCO's are satisfied.

The terms "Shutdown Rod Position Indicator," "Analog Rod Position Indicator," "Control Rod Position Indicator," and "Rod Position Indicator" are all used in this bases section or in Technical Specifications, and all refer to indication driven by the output of the Analog Rod Position Indication (ARPI) system.

One method for determining rod position are the indicators on the control console. An alternate method of determining rod position is the plant computer. Either the control console indicator or plant computer is sufficient to comply with this specification. The plant computer receives the same input from ARPI as the control console indicators and provides resolution equivalent to or better than the control console indicators. The plant computer also provides a digital readout of rod position which eliminates interpolation and parallax errors inherent to analog scales.

Rod demand position is indicated on the control console and the plant computer. The rod demand position is a digital signal, namely a pulse, and is generated each time the Rod Control System demands a rod position step change, one pulse for each rod step. The pulses are "counted" and displayed by the control console group demand step counters. There are two group demand step counters for each bank of rods with exception of shutdown banks C and D. The plant computer also "counts" and displays the demand pulses. Only the group 1 demand position of each rod bank is displayed on the plant computer as only the group 1 pulses are routed to the plant computer. The group 1 demand position on the plant computer is, by default, called "Cont Bank A Steps" or "S/D Bank A Steps" etc. with no reference to group 1 or group 2.

As the plant computer receives the same demand pulses from the Rod Control System as the control console group demand step counters and provides equivalent resolution, the plant computer "bank step" display provides an alternate method of determining group 1 rod demand position. Either the control console group 1 demand step counter or the plant computer "bank step" display is sufficient to comply with this specification for group 1 rod demand position. Only the control console group 2 demand counter can be used to comply with the specification for group 2 rod demand.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (a) meeting the DNB Design Criteria during normal operation and in short term transients, and (b) limiting the fission gas release, fuel pellet temperature and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is not exceeded.

The definitions of hot channel factors as used in these specifications are as follows:

$F_Q(Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

$F_{xy}(Z)$ Radial Peaking Factor is defined as the ratio of peak power density to average power density in the horizontal plane at core elevation Z.

3/4.2.1 AXIAL FLUX DIFFERENCE (AFD)

The limits on AXIAL FLUX DIFFERENCE assure that the $F_Q(Z)$ upper bound envelope of the F_Q limit specified in the CORE OPERATING LIMITS REPORT (COLR) times the normalized axial peaking factor is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

Target flux difference is determined at equilibrium xenon conditions with the part length control rods withdrawn from the core. The full length rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

Although it is intended that the plant will be operated with the AXIAL FLUX DIFFERENCE within the target band in the COLR per Specification 3.2.1 about the target flux difference, during rapid plant THERMAL POWER reductions, control rod motion will cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation will not affect the xenon redistribution sufficiently to change the envelope of peaking factors which may be reached on a subsequent return to RATED THERMAL POWER (with the AFD within the target band) provided the time duration of the deviation is limited. Accordingly, a 1 hour penalty deviation limit cumulative during the previous 24 hours is provided for operation outside of the target band but within the limits specified in the COLR while at THERMAL POWER levels between 50% and 90% of RATED THERMAL POWER. For THERMAL POWER levels between 15% and 50% of rated THERMAL POWER, deviations of the AFD outside of the target band are less significant. The penalty of 2 hours actual time reflects this reduced significance.

Provisions for monitoring the AFD are derived from the plant nuclear instrumentation system through the AFD Monitor Alarm. A control room recorder continuously displays the auctioneered high flux difference and the target band limits as a function of power level. An alarm is received any time the auctioneered high flux difference exceeds the target band limits. Time outside the target band is graphically presented on the strip chart.

Figure B 3/4 2-1 shows a typical monthly target band.

INFORMATION ONLY*

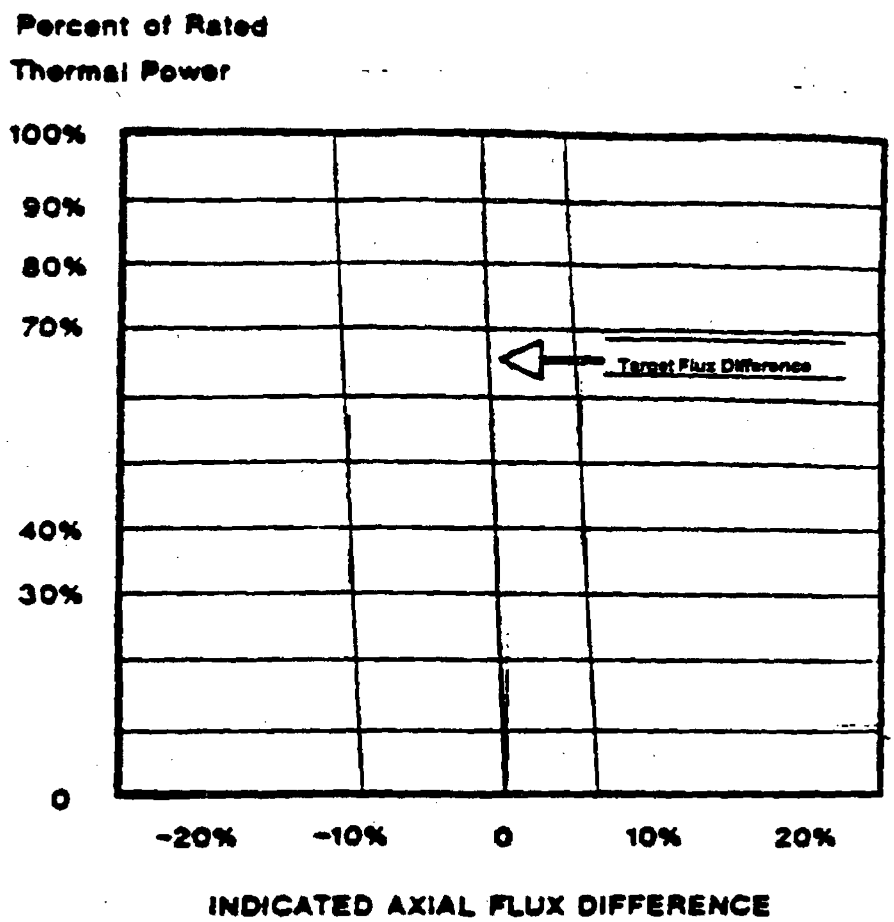


Figure B 3/4 2-1 TYPICAL INDICATED AXIAL FLUX DIFFERENCE VERSUS THERMAL POWER

* REFER TO COLR FIGURE 2 FOR ACTUAL LIMITS

3/4.2.2 and 3/4.2.3 HEAT FLUX AND NUCLEAR ENTHALPY HOT CHANNEL AND RADIAL PEAKING FACTORS - $F_Q(Z)$ AND $F^N_{\Delta H}$

The limits on heat flux and nuclear enthalpy hot channel factors and RCS flow rate ensure that 1) the design limits on peak local power density and minimum DNBR are not exceeded and 2) in the event of a LOCA the peak fuel clad temperature will not exceed the 2200°F ECCS acceptance criteria limit.

Each of these hot channel factors are measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to insure that the limits are maintained provided:

a. Control rod in a single group move together with no individual rod insertion differing from the group demand position by more than the allowed rod misalignment.

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.5.

c. The control rod insertion limits of Specifications 3.1.3.4 and 3.1.3.5 are maintained.

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

The relaxation in $F^N_{\Delta H}$ as a function of THERMAL POWER allows changes in the radial power shape for all permissible rod insertion limits. $F^N_{\Delta H}$ will be maintained within its limits provided conditions a through d above, are maintained.

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for. Five percent is the appropriate allowance for a full core map taken with the incore detector flux mapping system and 3% is the appropriate allowance for manufacturing tolerance. For measurements obtained using the Power Distribution Monitoring System (PDMS), the appropriate measurement uncertainty is determined using the measurement uncertainty methodology contained in WCAP 12472-P-A. The cycle and plant uncertainty calculation information needed to support the PDMS calculation is contained in the COLR. The PDMS will automatically calculate and apply the correct measurement uncertainty, and apply a 3% allowance for manufacturing tolerance.

When $F^N_{\Delta H}$ is measured, experimental error must be allowed for and is obtained from the COLR when using the PDMS or the incore detection system. The specified limit for $F^N_{\Delta H}$ also contains an 8% allowance for uncertainties which mean that normal operation will result in $F^N_{\Delta H} \le F^{RPT}_{\Delta H}/1.08$. Where $F^{RPT}_{\Delta H}$ is the limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT (COLR). The 8% allowance is based on the following considerations:

3/4.2.2 and 3/4.2.3 HEAT FLUX AND NUCLEAR ENTHALPY HOT CHANNEL AND RADIAL PEAKING FACTORS - $F_Q(Z)$ AND $F^N_{\Delta H}$ (Continued)

a. abnormal perturbations in the radial power shape, such as from rod misalignment, effect $F^N_{\Delta H}$ more directly than F_Q.

b. although rod movement has a direct influence upon limiting F_Q to within its limit, such control is not readily available to limit $F^N_{\Delta H}$, and

c. errors in prediction for control power shape detected during startup physics test can be compensated for in F_Q by restricting axial flux distributions. This compensation for $F^N_{\Delta H}$ is less rapidly available.

The appropriate measurement uncertainty for $F^N_{\Delta H}$ obtained using PDMS is determined using the measurement uncertainty methodology contained in WCAP 12472-P-A. The cycle and plant specific uncertainty information needed to support the PDMS calculation is contained in the COLR. The PDMS will automatically calculate and apply the correct measurement uncertainty to the measured $F^N_{\Delta H}$.

The radial peaking factor $F_{xy}(Z)$ is measured periodically to provide assurance that the hot channel factor $F_Q(Z)$, remains within its limit. The F_{xy} limit for RATED THERMAL POWER F^{RTP}_{xy}, as provided in COLR per specification 6.9.1.9, was determined from expected power control maneuvers over the full range of burnup conditions in the core.

3/4.2.4 QUADRANT POWER TILT RATIO

The quadrant power tilt ratio limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during startup testing and periodically during power operation.

The limit of 1.02 at which corrective action is required provides DNB and linear heat generation rate protection with x-y plane power tilts. A limiting tilt of 1.025 can be tolerated before the margin for uncertainty in F_Q is depleted. The limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2 hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the power by 3% from RATED THERMAL POWER for each percent of tilt in excess of 1.0.

3/4.2.5 DNB PARAMETERS

The limits on the DNB related parameters assure that each of the parameters are maintained with the normal steady state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR of the design DNBR value throughout each analyzed transient.

The 12 hour periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 18 month periodic measurement of the RCS total flow rate is adequate to detect flow degradation and ensure correlation of the flow indication channels with measured flow such that the indicated percent flow will provide sufficient verification of flow rate on a 12 hour basis.

3/4.3.1 and 3/4.3.2 PROTECTIVE AND ENGINEERED SAFETY FEATURES (ESF) INSTRUMENTATION

The OPERABILITY of the protective and ESF instrumentation systems and interlocks ensure that 1) the associated ESF action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation and, 3) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundance and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses.

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as-left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy).

The Trip Setpoints used in the bistables are based on the analytical limits stated in the UFSAR. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those Reactor Protection System (RPS) channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints and Allowable Values specified in the Technical Specification Limiting Conditions for Operation (LCO's) are conservatively adjusted with respect to the analytical limits. The methodology used to calculate the Trip Setpoints is consistent with Instrument Society of America standard ISA-S67.04-1982, which is endorsed via NRC Regulatory Guide 1.105, Rev. 2. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the safety analyses which demonstrate that safety limits are not violated remain valid (provided the unit is operated within the LCO's at the onset of any design basis event and the equipment functions as designed).

The Trip Setpoints and Allowable Values listed in the LCO's incorporate all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance

Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and Supplements to that report. Surveillance intervals and out of service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.

The verification of response time at the specified frequencies provides assurance that the reactor trip and the engineered safety features actuation associated with each channel is completed within the time limit assumed in the safety analysis. Response time acceptance criteria have been relocated to UFSAR Sections 7.2 and 7.3 tables. No credit is taken in the analysis for those channels with response times indicated as not applicable (i.e., N.A.).

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types, and other components that do not have plant-specific NRC approval to use alternate means of verification, must be demonstrated by test.

The allocation for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

Channel testing in a bypassed condition shall be performed without lifting leads or jumpering bistables.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring channels ensures that 1) the radiation levels are continually measured in the areas served by the individual channels and 2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded.

In the postulated Fuel Handling Accident, the revised dose calculations, performed using 10 CFR 50.67 and Regulatory Guide 1.183, Alternative Source Term, do not take credit for automatic containment purge isolation thus allowing for continuous monitoring of containment activity until containment closure is achieved. If required, containment purge isolation can be initiated manually from the control room.

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION (Continued)

CROSS REFERENCE - TABLES 3.3-6 and 4.3-3

T/S Table Item No.	**Instrument Description**	**Acceptable RMs Channels**
1a	Fuel Storage Area	2R5 or 2R9
1b	DELETED	
2a1a	Containment Gaseous Activity Purge & Pressure/Vacuum Relief Isolation	2R12A or 2R41A, B and D(1) (2)
2a1b	Containment Gaseous Activity RCS Leakage Detection	2R12A
2a2a	(NOT USED)	
2a2b	Containment Air Particulate Activity RCS Leakage Detection	2R11A
2b1	Noble Gas Effluent Medium Range Auxiliary Building Exhaust System (Plant Vent)	2R45B(3)
2b2	Noble Gas Effluent High Range Auxiliary Building Exhaust System (Plant Vent)	2R45C(3)
2b3	DELETED	
2b4	Noble Gas Effluent Condenser Exhaust System	2R15
3a	Unit 2 Control Room Intake Channel 1 (to Unit 2 Monitor) Unit 2 Control Room Intake Channel 2 (to Unit 1 Monitor) Unit 1 Control Room Intake Channel 1 (to Unit 1 Monitor) Unit 1 Control Room Intake Channel 2 (to Unit 2 Monitor)	2R1B-1 1R1B-2 1R1B-1 2R1B-2

(1) The channels listed are required to be operable to meet a single operable channel for the Technical Specification's "Minimum Channels Operable" requirement.

(2) For Modes 1, 2, 3, 4 & 5, the setpoint applies to 2R41D per Specification 3.3.3.9. The measurement range applies to 2R41A and B which display in uCi/cc using the appropriate channel conversion factor from cpm to uCi/cc.

(3) If 2R45 is out of service 2R41 may be used to meet the technical specification action requirement.

Immediate action(s), in accordance with the LCO Action Statements, means that the required action should be pursued without delay and in a controlled manner.

3/4.3.3.2

THIS SECTION DELETED

3/4.3.3.3

THIS SECTION DELETED

3/4.3.3.4

THIS SECTION DELETED

3/4.3.3.5 REMOTE SHUTDOWN INSTRUMENTATION

The OPERABILITY of the remote shutdown instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of HOT STANDBY of the facility from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR 50.

3/4.3.3.6

THIS SECTION DELETED

3/4.3.3.7 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with the Recommendations of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0578,"TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations."

3/4.3.3.8 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The purpose of tank level indicating devices is to assure the detection and control of leaks that if not controlled could potentially result in the transport of radioactive materials to UNRESTRICTED AREAS.

3/4.3.3.9

THIS SECTION DELETED

3/4.3.3.10

THIS SECTION DELETED

3/4.3.3.11

THIS SECTION DELETED

3/4.3.3.12

THIS SECTION DELETED

3/4.3.3.13

THIS SECTION DELETED

3/4.3.4 Deleted

3/4.3.3.14 POWER DISTRIBUTION MONFTORING SYSTEM (PDMS)

The Power Distribution Monitoring System (PDMS) provides core monitoring of the limiting parameters. The PDMS continuous core power distribution measurement methodology begins with the periodic generation of a highly accurate 3-D nodal simulation of the current reactor power distribution. The simulated reactor power distribution is then continuously adjusted by nodal and thermocouple calibration factors derived from an incore power distribution measurement obtained using the incore movable detectors to produce a highly accurate power distribution measurement. The nodal calibration factors are updated at least once every 180 Effective Full Power Days (EFPD). Between calibrations, the fidelity of the measured power distribution is maintained via adjustment to the calibrated power distribution provided by continuously input plant and core condition information. The plant and core condition data utilized by the PDMS is cross checked using redundant information to provide a robust basis for continued operation. The loop inlet temperature is generated by averaging the respective temperatures from each of the loops, excluding any bad data. The core exit thermocouples provide many readings across the core and by the nature of their usage with the PDMS, smoothing of the measured data and elimination of bad data is performed with the Surface Spline fit. PDMS uses the NIS Power Range excore detectors to provide information on the axial power distribution. Hence, the PDMS averages the data from the four Power Range excore detectors and eliminates any bad excore detector data.

The bases for the operability requirements of the PDMS is to provide assurance of the accuracy and reliability of the core parameters measured and calculated by the PDMS core power distribution monitor function. These requirements fall under four categories:

1. Assure an adequate number of operable critical sensors.

2. Assure sufficiently accurate calibration of these sensors.

3. Assure an adequate calibration database regarding the number of data sets.

4. Assure the overall accuracy of the calibration.

The minimum number of required plant and core condition inputs include the following:

1. Control Bank Positions.

2. At least 50% of the cold leg temperatures.

3. At least 75% of the signals from the power range excore detector channels (comprised of top and bottom detector section).

4. Reactor Power Level.

5. A minimum number and distribution of operable core exit thermocouples.

6. A minimum number and distribution of measured fuel assembly power distribution information obtained using the incore movable detectors is incorporated in the nodal model calibration information.

The sensor calibration of Items 1, 2, 3, and 4 above are covered under other specifications. Calibration of the core exit thermocouples is accomplished in two parts. The first being a sensor specific correction to K-type thermocouple temperature indications based on data from a cross calibration of the thermocouple temperature indications to the average RCS temperature measured via the RTDs under isothermal RCS conditions. The second part of the thermocouple calibration is the generation of thermocouple flow mixing factors that cause the radial power distribution measured via the thermocouples to agree with the radial power distribution from a full core flux map measured using the incore movable detectors. This calibration is updated at least once every 180 EFPD.

The operability requirements previously contained in Specification 3.3.3.2 have been moved to UFSAR Section 7.7.2.8 as part of Amendment 265.

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with all reactor coolant loops in operation, meet the DNB design criteria during all normal operations and anticipated transients. In MODES 1 and 2 with less than all coolant loops in operation, this specification requires that the plant be in at least HOT STANDBY within 1 hour.

In MODE 3, a single reactor coolant loop provides sufficient heat removal for removing decay heat; but, single failure considerations require all loops be in operation whenever the rod control system is energized and at least one loop be in operation when the rod control system is deenergized.

In MODE 4, a single reactor coolant loop or RHR loop provides sufficient heat removal for removing decay heat; but, single failure considerations require that at least 2 loops be OPERABLE. Thus, if the reactor coolant loops are not OPERABLE, this specification requires that two RHR loops be OPERABLE.

In MODE 5, single failure considerations require that two RHR loops be OPERABLE. For support systems: Service Water (SW) and Component Cooling (CC), component redundancy is necessary to ensure no single active component failure will cause the loss of Decay Heat Removal. One piping path of SW and CC is adequate when it supports both RHR loops. The support systems needed before entering into the desired configuration (e.g., one service water loop out for maintenance in Modes 5 and 6) are controlled by procedures, and include the following:

- A requirement that two RHR, two CC and two SW pumps, powered from two different vital buses be kept operable
- A listing of the active (air/motor operated) valves in the affected flow path to be locked open or disabled

Note that four filled reactor coolant loops, with at least two steam generators with at least their secondary side water level greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop. This ensures that a single failure does not cause a loss of decay heat removal.

The operation of one Reactor Coolant Pump or one RHR Pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during Boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with Boron concentration reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump below P-7 with one or more RCS cold legs less than or equal to 312°F are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by either (1) restricting the water volume in the pressurizer (thereby providing a volume into which the primary coolant can expand, or (2) by restricting the starting of Reactor Coolant Pumps to those times when secondary water temperature in each steam generator is less than 50°F above each of the RCS cold leg temperatures.

3/4.4.2 and 3/4.4.3 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 420,000 pounds per hour of saturated steam at the valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating RHR loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Protection System provides a diverse means of protection against RCS overpressurization at low temperature. While in Mode 5 the safety valve requirement may be met by establishing a vent path of equivalent relieving capacity when no code safety valves are OPERABLE.

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss of load assuming no reactor trip until the first Reactor Protective System trip setpoint is reached (i.e., no credit is taken for a direct reactor trip on the loss of load) and also assuming no operation of the power operated relief valves or steam dump valves.

Demonstration of the safety valves lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code.

Surveillance testing allows a ± 3% lift setpoint tolerance. However, to allow for drift during subsequent operation, the valves must be reset to within ± 1% of the lift setpoint following testing.

3/4.4.4 PRESSURIZER

The limit on the maximum water volume in the pressurizer assures that the parameter is maintained within the normal steady-state envelope of operation assumed in the SAR. The limit is consistent with the initial SAR assumptions. The 12 hour periodic surveillance is sufficient to ensure that the parameter is restored to within its limit following expected transient operation. The maximum water volume also ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that a minimum number of pressurizer heaters be OPERABLE enhances the capability of the plant to control RCS pressure and establish natural circulation.

3/4.4.5 RELIEF VALVES

The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

A. Manual control of PORVs to control reactor coolant system pressure. This is a function that is used for the steam generator tube rupture accident and for plant shutdown.

3/4.4.5 RELIEF VALVES (continued)

B. Automatic control of PORVs to control reactor coolant system pressure. This is a function that reduces challenges to the code safety valves for overpressurization events, including an inadvertent actuation of the Safety Injection System.

C. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

D. Manual control of the block valve to : (1) unblock an isolated PORV to allow it to be used for manual and automatic control of Reactor Coolant System pressure (Items A & B), and (2) isolate a PORV with excessive seat leakage (Item C).

E. Manual control of a block valve to isolate a stuck-open PORV.

3/4.4.6 STEAM GENERATOR (SG) TUBE INTEGRITY

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The portion of the tube within the hot-leg tubesheet region below the W* distance is excluded. The excluded portion of the tube defined by W* is ONLY applicable to Westinghouse Model 51 SGs with mill annealed Alloy 600 tubing expanded into the tubesheet using the Westinghouse explosive tube expansion (WEXTEX) process. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.i, "Steam Generator (SG) Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that significantly affect burst or collapse. In that context, the term "significant" is defined as, "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB and draft Reg. Guide 1.121.

The accident induced leakage performance criterion ensures that the primary-to-secondary leakage caused by a design basis accident, other than a steam generator tube rupture (SGTR), is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm per SG. The accident induced leakage rate includes any primary-to-secondary leakage existing prior to the accident in addition to primary-to-secondary leakage induced during the accident.

The operational leakage performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational leakage is contained in LCO 3.4.7.2, "Operational Leakage," and limits primary-to-secondary leakage through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of leakage is due to more than one crack, the cracks are very small, and the above assumption is conservative.

The ACTION requirements are modified by a Note clarifying that the Actions may be entered independently for each SG tube. This is acceptable because the Action requirements provide appropriate compensatory actions for each affected SG tube. Complying with the Action requirements may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Action requirements.

If it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program, an evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. An action time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity. If the evaluation determines that the affected tube(s) have tube integrity, plant operation is allowed to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering HOT SHUTDOWN following the next refueling outage or SG inspection. This allowed outage time is acceptable since operation until the next inspection is supported by the operational assessment.

If SG tube integrity is not being maintained or the Action requirements are not met, the reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within 36 hours. The action times are reasonable based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

During shutdown periods the SGs are inspected as required by surveillance requirements and the Steam Generator Program. NEI 97-06, "Steam Generator Program Guidelines," and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period. The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, nondestructive examination (NDE) technique capabilities and inspection locations. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines.

The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.8.4.i contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 6.8.4.i are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in size measurement and future growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). NEI 97-06 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria. The Frequency of prior to entering HOT SHUTDOWN following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary-to-secondary pressure differential.

License Change Request (LCR) S05-07 (LR-N05-0397, LR-N06-0277, LR-N06-0338) provides requirements for limited tubesheet inspection that is only applicable within the hot leg WEXTEX expanded region of the tubesheet for the Salem Unit 2 Westinghouse Series 51 Steam Generators. LCR S05-07 is supported by, but not limited to, the guidance provided in WCAP-14797, Revision 2, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions" and supporting information provided from Westinghouse Letter Report LTR-CDME-05-30, "W* Integrity Evaluation for Salem Unit 2 Limited SG Tube RPC Examination (Based on WCAP-14797, Revision 2). In accordance with LCR S05-07, the W* Length is the undegraded length of tubing into the tubesheet below the bottom of the WEXTEX transition (BWT) that precludes tube pullout in the event of a complete circumferential separation of the tube below the W* Length. For the hot leg, the W* Length is 7.0 inches, which represents the most conservative hot leg length defined in WCAP-14797, Revision 2. The W* Distance is the larger of the following two distances as measured from the top-of-the-tubesheet (TTS): (a) 8-inches below the TTS or (b) the non-degraded distance from the TTS to the bottom of the W* Length, including the distance from the TTS to the bottom of the WEXTEX transition (BWT) and Non-Destructive Examination (NDE) measurement uncertainties (i.e., W* Distance = W* Length + distance to BWT + NDE uncertainties). Non-Destructive Examination determines the distance to the BWT for each tube. The nondestructive examination (NDE) measurement uncertainty is provided from LCR S05-07, as supported by WCAP-14797 Revision 2. Tubes with indications detected within the W* Distance will be removed from service by tube plugging.

Tube degradation of any type or extent below the W* Distance, including a complete circumferential separation of the tube, is acceptable and therefore may remain in service. As applied at Salem Unit 2, LCR S05-07 is used to define the required tube inspection depth into the tubesheet, and is not used to permit degradation in the W* Distance to remain in service. Furthermore, potential primary to secondary leakage in the W* Distance, and below the W* Distance, can be conservatively evaluated in accordance with LCR S05-07. The leak rate potential for axial, circumferential, and volumetric indications detected within 12 inches from the top of the tubesheet can be conservatively calculated using the constrained crack model as delineated in LCR S05-07 (supported by Westinghouse LTR-CDME-05-30).

The postulated leakage during a steam line break shall be equal to the following equation, as supported by LCR S05-07:

Postulated SLB Leakage = Assumed Leakage $_{0''-8''\ <TTS}$ + Assumed Leakage $_{8''-12''\ <TTS}$ + Assumed Leakage $_{>12''\ <TTS}$

Where: Assumed Leakage $_{0''-8''\ <TTS}$ is the postulated leakage for indications that are deemed via flaw depth estimation techniques to be 100% throughwall, and therefore present a potential leak path. This term is applicable to detected indications during an in-service inspection and potentially undetected indications in the steam generator tubes left in service between 0 inches and 8 inches below the top of the tubesheet (TTS). Since tubes with indications detected between 0 and 8 inches below the TTS are plugged upon detection, the calculation of this term for the assessment of SLB leakage for the subsequent operation cycle following an in-service inspection only requires consideration of potentially undetected indications. The calculation of this term for the assessment of SLB leakage for the previous operation cycle, following an in-service inspection, requires consideration of both detected and potentially undetected indications.

Assumed Leakage $_{''8-12''\ <TTS}$ is the conservatively projected leakage in steam generator tubes between 8 and 12 inches below the top of the tubesheet. Implementation of LCR S05-07 does not require tube inspection below the W* Distance, therefore the methodology for conservatively calculating the population of indications between 8 and 12 inches below the TTS is provided by fitting a

regression line to the cumulative inspection data (detected indications) from all SGs and projecting the number of indications (to minus 12 inches below TTS) using a 95-percent probability prediction bound. The cumulative indications from all steam generators are conservatively assumed to occur in one SG (similar to figure 16 of Westinghouse LTR-CDME-05-30). The conservative leakage rate for the indications between 8 and 12 inches is 0.0033 gpm multiplied by the number of projected indications (as discussed in LCR S05-07 submittals LR-N06-0277 and LR-N06-0338). The leak rate of indications detected between 8 and 12 inches are bounded by the projected total discussed above, assuming that the inspection results for detected indications do not contradict the calculated population as described previously.

Assumed Leakage $_{>12'' <TTS}$ is the calculated leakage from the steam generator tubes left in service below 12 inches from the top of the tubesheet. This is 0.00009 gpm times number of tubes left in service in the steam generator.

Each SG is assessed for Main Steam Line Break (MSLB) leakage individually in accordance with the discussion above, and the SG with the most calculated leakage is conservatively assigned as the affected SG.

The calculated MSLB leakage provided above, including MSLB leakage from all other sources, shall be reported to the NRC in accordance with applicable Technical Specifications. The Calculated MSLB Leakage must be less than the maximum allowable MSLB leak rate limit in any one steam generator in order to maintain doses within 10 CFR 50.67 guideline values and within GDC-19 values during a postulated main steam line break event.

3/4.4.7 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.7.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the Reactor Coolant Pressure Boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3/4.4.7.2 OPERATIONAL LEAKAGE

Industry experience has shown that while a limited amount of leakage is expected from the RCS, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 GPM. This threshold value is sufficiently low to ensure early detection of additional leakage.

The 10 GPM IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the leakage detection systems.

The surveillance requirements for RCS Pressure Isolation Valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS Pressure Isolation Valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

Primary to Secondary Leakage Through Any One SG

The primary-to-secondary leakage rate limit applies to leakage through any one Steam Generator. The limit of 150 gallons per day per steam generator is based on the operational leakage performance criterion in NEI 97-06, Steam Generator Program Guidelines. The Steam Generator Program operational leakage performance criterion in NEI 97-06 states, "The RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with steam generator tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures. The dosage contribution from the tube leakage will be within 10 CFR 50.67 limits in the event of either a steam generator tube rupture or steam line break. The analyses are based on the total primary to secondary leakage from all SGs of 1 gallon per minute as a result of accident induced conditions.

3/4.4.7.2 OPERATIONAL LEAKAGE (Continued)

Actions
Unidentified leakage or identified leakage in excess of the LCO limits must be reduced to within limits within 4 hours. This action time allows time to verify leakage rates and either identify unidentified leakage or reduce leakage to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the reactor coolant pressure boundary (RCPB). If any pressure boundary leakage exists, or primary-to-secondary leakage is not within limit, or if unidentified or identified leakage cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the leakage and its potential consequences. It should be noted that leakage past seals and gaskets is not pressure boundary leakage. The reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within 36 hours. This action reduces the leakage and also reduces the factors that tend to degrade the pressure boundary. The action times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In COLD SHUTDOWN, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

Surveillances
Verifying RCS leakage to be within the LCO limits ensures the integrity of the Reactor Coolant Pressure Boundary is maintained. Pressure boundary leakage would at first appear as unidentified leakage and can only be positively identified by inspection. It should be noted that leakage past seals and gaskets is not pressure boundary leakage. Unidentified leakage and identified leakage are determined by performance of an RCS water inventory balance. The RCS water inventory must be met with the reactor at steady state operating conditions. The surveillance is modified by a Note that the surveillance is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational leakage determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows. The 72 hour frequency is a reasonable interval to trend leakage and recognizes the importance of early leakage detection in the prevention of accidents.

Satisfying the primary-to-secondary leakage limit ensures that the operational leakage performance criterion in the Steam Generator Program is met. If SR 4.4.7.2.1.c is not met, compliance with LCO 3.4.6, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature (in accordance with EPRI PWR Primary-to-Secondary Leak Guidelines). If it is not practical to assign the leakage to an individual steam generator, all the primary-to-secondary leakage should be conservatively assumed to be from one Steam Generator. The Surveillance is modified by a Note that states that the surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary-to-secondary leakage determination, steady

3/4.4.7.2 OPERATIONAL LEAKAGE (Continued)

state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows. The Surveillance Frequency of 72 hours is a reasonable interval to trend primary-to-secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling (in accordance with EPRI PWR Primary-to-Secondary Leak Guidelines).

3/4.4.8

THIS SECTION DELETED

3/4.4.9 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the resulting 2 hour doses at the site boundary will not exceed an appropriately small fraction of Part 100 limits following a steam generator tube rupture accident in conjunction with an assumed steady state primary-to-secondary steam generator leakage rate of 1.0 GPM. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters of the Salem site, such as site boundary location and meteorological conditions, were not considered in this evaluation. The NRC is finalizing site specific criteria which will be used as the basis for the reevaluation of the specific activity limits of this site. This reevaluation may result in higher limits.

Reducing T_{avg} to less than 500°F prevents the release of activity should a steam generator tube rupture occur since the saturation pressure of the primary coolant is below the lift pressure of the atmospheric steam relief valves. The surveillance requirements provide adequate assurance that excessive specific activity levels in the primary coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

LCO 3.0.4.c is applicable. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS.

3/4.4.10 PRESSURE/TEMPERATURE LIMITS

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G.

1) The reactor coolant temperature and pressure and system heatup and cooldown rate (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 and 3.4-3 for the service period specified thereon.

   a) Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation.

   b) Figures 3.4-2 and 3.4-3 define limits to assure prevention of nonductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

2) These limit lines shall be calculated periodically using methods provided below.

3) The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F.

4) The pressurizer heatup and cooldown rates shall not exceed 100°F/hr and 200°F/hr, respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

5) System preservice hydrotests and in-service leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, ASTM E185-82, and in accordance with additional reactor vessel requirements. These properties are then evaluated in accordance with Appendix G of the 1996 Summer Addenda to Section XI of the ASME Boiler and Pressure Vessel Code and the calculation methods described in WCAP-14040-NP-A, Rev. 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves", January 1996, and ASME Boiler and Pressure Vessel Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves for Section XI, Division 1", approved March 1999.

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RT_{NDT}, at the end of 32 effective full power years of service life. The 32 EFPY service life period is chosen such that the limiting RT_{NDT} at the 1/4T location in the core region is greater than the RT_{NDT} of the limiting unirradiated material. The selection of such a limiting RT_{NDT} assures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Table B 3/4.4-1. Reactor operation and resultant fast neutron (E greater than 1 MEV) irradiation can cause an increase in the RT_{NDT}. An adjusted reference temperature, (ART), based upon the fluence and the copper and nickel content of the material in question, can be predicted.

The ART is based upon the largest value of RT_{NDT} computed by the methodology presented in Regulatory Guide 1.99, Revision 2. The ART for each material is given by the following expression:

$$ART = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin}$$

Initial RT_{NDT} is the reference temperature for the unirradiated material. ΔRT_{NDT} is the mean value of the adjustment in reference temperature caused by the irradiation and is calculated as follows:

$$\Delta RT_{NDT} = \text{Chemistry Factor} \times \text{Fluence Factor}$$

The Chemistry Factor, CF (F), is a function of copper and nickel content. It is given in Table B3/4.4-2 for welds and in Table B3/4.4-3 for base metal (plates and forgings). Linear interpolation is permitted.

The predicted neutron fluence as a function of Effective Full Power Years (EFPY) has been calculated and is shown in Figure B3/4.4-1. The fluence factor can be calculated by using Figure B3/4.4-2. Also, the neutron fluence at any depth in the vessel wall is determined as follows:

$$f = (f \text{ surface}) \times (e^{-0.24X})$$

where "f surface" is from Figure B3/4.4-1, and X (in inches) is the depth into the vessel wall.

Finally, the "Margin" is the quantity in °F that is to be added to obtain conservative, upper-bound values of adjusted reference temperature for the calculations required by Appendix G to 10 CFR 50.

$$\text{Margin} = 2\sqrt{\sigma_I^2 + \sigma_\Delta^2}$$

If a measured value of initial RT_{NDT} for the material in question is used, σ_I may be taken as zero. If generic value of initial RT_{NDT} is used, σ_I should be obtained from the same set of data. The standard deviations, for ΔRT_{NDT}, σ_Δ, are 28°F for welds and 17°F for base metal, except that σ_Δ need not exceed 0.50 times the mean value of ΔRT_{NDT} surface.

The heatup and cooldown limit curves of Figures 3.4-2 and 3.4-3 include predicted adjustments for this shift in RT_{NDT} at the end of 32 EFPY.

Values of ΔRT_{NDT} determined in this manner may be used until the results from the material surveillance program, evaluated according to ASTM E185, are available. Capsules will be removed in accordance with the requirements of ASTM E185-82 and 10 CFR Part 50, Appendix H. The heatup and cooldown curves must be recalculated when the ΔRT_{NDT} determined from the surveillance capsule exceeds the calculated ΔRT_{NDT} for the equivalent capsule radiation exposure.

Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Appendix G in Section XI of the ASME Boiler and Pressure Vessel Code as required by Appendix G to 10 CFR Part 50 and these methods are discussed in detail in WCAP-14040-NP-A, Rev. 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves", January 1996, and ASME Boiler and Pressure Vessel Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves for Section XI, Division 1", approved March 1999.

The general method for calculating heatup and cooldown limit curves is based upon the principles of the linear elastic fracture mechanics (LEFM) technology. In the calculation procedures a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, T, and a length of 3/2T is assumed to exist at the inside of the vessel wall as well as at the outside of the vessel wall. The dimensions of this postulated crack, referred to in Appendix G of ASME Section XI as the reference flaw, amply exceed the current capabilities of inservice inspection techniques. Therefore, the reactor operation limit curves developed for this reference crack are conservative and provide sufficient safety margins for protection against nonductile failure. To assure that the radiation embrittlement effects are accounted for in the calculation of the limit curves, the most limiting value of the nil-ductility reference temperature, RT_{NDT}, is used and this includes the radiation induced shift, ΔRT_{NDT} corresponding to the end of the period for which heatup and cooldown curves are generated.

The ASME approach for calculating the allowable limit curves for various heatup and cooldown rates specifies that the total stress intensity factor, K_I, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, K_{IC}, for the metal temperature at that time. K_{IC} is obtained from the reference fracture toughness curve, defined in ASME Code Case N-640. The K_{IC} curve is given by the equation:

$$K_{IC} = 33.2 + 20.734 \exp\,[0.02(T-RT_{NDT})] \qquad (1)$$

where K_{IC} is the reference stress intensity factor as a function of the metal temperature T and the metal nil-ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\,K_{IM} + K_{IT} \leq K_{IC} \qquad (2)$$

where K_{IM} is the stress intensity factor caused by membrane (pressure) stress.

K_{IT} is the stress intensity factor caused by the thermal gradients.

K_{IC} is provided by the code as a function of temperature relative to the RT_{NDT} of the material.

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{IC} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding (thermal) stress intensity factors, K_{IT}, for the reference flaw are computed. From Equation (2) the pressure stress intensity factors are obtained and from these the allowable pressures are calculated.

COOLDOWN

For the calculation of the allowable pressure versus coolant temperature during cooldown, the Code reference flaw is assumed to exist at the inside of the vessel wall. During cooldown, the controlling location of the flaw is always at the inside of the wall because the thermal gradients produce tensile stresses at the inside, which increase with increasing cooldown rates. Allowable pressure-temperature relations are generated for both steady-state and finite cooldown rate situations. From these relations composite limit curves are constructed for each cooldown rate of interest.

The use of the composite curve in the cooldown analysis is necessary because control of the cooldown procedure is based on measurement of reactor coolant temperature, whereas the limiting pressure is actually dependent on the material temperature at the tip of the assumed flaw. During cooldown, the 1/4T vessel location is at a higher temperature than the fluid adjacent to the vessel ID. This condition, of course, is not true for the steady-state situation. It follows that at any given reactor coolant temperature, the ΔT developed during cooldown results in a higher value of K_{IC} at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if conditions exist such that the increase in K_{IC} exceeds K_{IT}, the calculated allowable pressure during cooldown will be greater than the steady-state value.

The above procedures are needed because there is no direct control on temperature at the 1/4T location, therefore, allowable pressures may unknowingly be violated if the rate of cooling is decreased at various intervals along a cooldown ramp. The use of the composite curve eliminates this problem and assures conservative operation of the system for the entire cooldown period.

HEATUP

Three separate calculations are required to determine the limit curves for finite heatup rates. As is done in the cooldown analysis, allowable pressure-temperature relationships are developed for steady-state conditions as well as finite heatup rate conditions assuming the presence of a 1/4T defect at the inside of the vessel wall. The thermal gradients during heatup produce compressive stress at the inside of the wall that alleviate the tensile stresses produced by internal pressure. The metal temperature at the crack tip lags the coolant temperature. Therefore, the K_{IC} for the 1/4T crack during heatup is lower than the K_{IC} for the 1/4T crack during steady-state conditions at the same coolant temperature. During heatup, especially at the end of the transient, conditions may exist such that the effects of compressive thermal stresses and different K_{IC}s for steady-state and finite heatup rates do not offset each other and the pressure-temperature curve based on steady-state conditions no longer represents a lower bound of all similar curves for finite heatup rates when the 1/4T flaw is considered. Therefore, both cases have to be analyzed in order to assure that at any coolant temperature the lower value of the allowable pressure calculated for steady-state and finite heatup rates is obtained.

The second portion of the heatup analysis concerns the calculation of pressure-temperature limitations for the case in which a 1/4T deep outside surface flaw is assumed. Unlike the situation at the vessel inside surface, the thermal gradients established at the outside surface during heatup produce stresses which are tensile in nature and thus tend to reinforce any pressure stresses present. These thermal stresses, of course, are dependent on both the rate of heatup and the time (or coolant temperature) along the heatup ramp. Furthermore, since the thermal stresses, at the outside are tensile and increase with increasing heatup rate, a lower bound curve cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

Following the generation of pressure-temperature curves for both the steady-state and finite heatup rate situations, the final limit curves are produced as follows. A composite curve is constructed based on a point-by-point comparison of the steady-state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the three values taken from the curves under consideration.

The use of the composite curve is necessary to set conservative heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling condition switches from the inside to the outside and the pressure limit must at all times be based on analysis of the most critical criterion.

Finally, the new 10CFR50 rule which addresses the metal temperature of the closure head flange regions is considered. This 10CFR50 rule states that the metal temperature of the closure flange regions must exceed the material RT_{NDT} by at least 120°F for normal operation when the pressure exceeds 20 percent of the preservice hydrostatic test pressure (621 psig for Salem). Table B3/4.4-1 indicates that the limiting RT_{NDT} of 28°F occurs in the closure head flange of Salem Unit 2, and the minimum allowable temperature of this region is 148°F at pressures greater than 621 psig. These limits do not affect Figures 3.4-2 and 3.4-3.

Although the pressurizer operates in temperature ranges above those for which there is reason for concern of non-ductile failure, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Code requirements.

The OPERABILITY of two POPSs or an RCS vent opening of greater than 3.14 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 312°F. Either POPS has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 50°F above the RCS cold leg temperatures, or (2) the start of an Intermediate Head Safety Injection pump and its injection into a water solid RCS, or the start of a High Head Safety Injection pump in conjunction with a running Positive Displacement pump and its injection into a water solid RCS. The minimum electrical power sources required to assure POPS operability (based on POPS meeting the single failure criteria) consist of a normal (via offsite power) and an emergency (via batteries) power source for each train of POPS. Emergency diesel generators are not required for POPS to meet single failure criteria and therefore are not required for POPS OPERABILITY.

LCO 3.0.4.b is not applicable to an inoperable LTOP system when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable LTOP system. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

TABLE 3/4.4-1
SALEM UNIT 2 REACTOR VESSEL TOUGHNESS DATA

Component	Plate No. or Weld No.	Material Type	Cu (%)	Ni (%)	T (°F)	50 ft-lb 35 - Mil Temp (°F)	RT (°F)	Average Upper Shell Energy	
								Normal to Principal Working Direction (ft-lb)	Principal Working Direction (ft-lb)
Closure Hd Dome	B4708	A533BCL1	0.11	0.70	-40	45*	-15*	82.5	127
Closure Hd Peel	B5007-3	A533BCL1	0.12	0.57	-20	15*	-20*	97*	149
Closure Hd Peel	B4707-1	A533BCL1	0.10	0.55	0	51*	0*	84*	129
Closure Hd Peel	B4707-3	A533BCL1	0.13	0.63	0	66*	6*	84*	129.5
Closure Hd Flng	B4702-1	A508CL2	-	0.68	28*	39*	28*	104*	160
Vessel Flange	B5001	A508CL2	-	0.70	12*	4*	12*	107*	164
Inlet Nozzle	B4703-1	A508CL2	-	0.69	60*	62*	60*	>72*	>111**
Inlet Nozzle	B4703-2	A508CL2	-	0.69	60*	25*	60*	>61*	>94**
Inlet Nozzle	B4703-3	A508CL2	-	0.68	60*	32*	60*	>71*	>109**
Inlet Nozzle	B4703-4	A508CL2	-	0.81	60*	40*	60*	80*	123.5
Outlet Nozzle	B4704-1	A508CL2	-	0.84	60*	8*	60*	82*	126
Outlet Nozzle	B4704-2	A508CL2	-	0.77	60*	20*	60*	75*	116
Outlet Nozzle	B4704-3	A508CL2	-	0.69	28*	8*	28*	82*	126
Outlet Nozzle	B4704-4	A508CL2	-	0.71	60*	40*	60*	77*	119
Upper Shell	B4711-1	A533BCL1	0.11	0.55	0*	50*	0*	87*	134
Upper Shell	B4711-2	A533BCL1	0.14	0.56	-10	60*	0*	79*	122
Upper Shell	B4711-3	A533BCL1	0.12	0.58	-10	88*	28*	69*	107
Inter. Shell	B4712-1	A533BCL1	0.13	0.56	0	<60	0	106	138
Inter. Shell	B4712-2	A533BCL1	0.12	0.62	-20	72	12	97	127.5
Inter. Shell	B4712-3	A533BCL1	0.11	0.57	-50	70	10	107	116
Lower Shell	B4713-1	A533BCL1	0.12	0.60	-10	68	8	98	127
Lower Shell	B4713-2	A533BCL1	0.12	0.57	-20	68	8	103	135.5
Lower Shell	B4713-3	A533BCL1	0.12	0.58	-10	70	10	121	135.5
Bottom Hd Peel	B4709-1	A533BCL1	0.12	0.60	-30	54*	-6*	90*	139
Bottom Hd Peel	B4709-2	A533BCL1	0.12	0.58	-20	42*	-18*	89*	137.5
Bottom Hd Peel	B4709-3	A533BCL1	0.11	0.56	-20	71*	11*	93*	143
Bottom Head	B4710	A533BCL1	0.12	0.60	-30	60*	0*	77*	118
Circum. Weld Bet Nozzle Shell & Int. Shell	8-442	-	0.28	0.74	-	-	-56***	-	-
Circum. Weld Bet Int. Shell & Lower Shell	9-442	-	0.197	0.060	-	-	-56***	99.7	-
Int. Shell Vertical Weld	2-442 [A,B,C]	-	0.219	0.735	-	-	-56***	96.2	-
Lower Shell Vertical Weld	3-442 [A,B,C]	-	0.213	0.867	-	-	-56***	114	-

* Estimated per NRC Standard Review Plan Section 5.8.2.
** 100% Shear not reached
*** Estimate per Pressurized Thermal Shock Rule, 10 CFR 50.61

TABLE B 3/4.4.2

CHEMISTRY FACTOR FOR WELDS, °F

Copper, Wt-%	Nickel, Wt-%						
	0	0.20	0.40	0.60	0.80	1.00	1.20
0	20	20	20	20	20	20	20
0.01	20	20	20	20	20	20	20
0.02	21	26	27	27	27	27	27
0.03	22	35	41	41	41	41	41
0.04	24	43	54	54	54	54	54
0.05	26	49	67	68	68	68	68
0.06	29	52	77	82	82	82	82
0.07	32	55	85	95	95	95	95
0.08	36	58	90	106	108	108	108
0.09	40	61	94	115	122	122	122
0.10	44	65	97	122	133	135	135
0.11	49	68	101	130	144	148	148
0.12	52	72	103	135	153	161	161
0.13	58	76	106	139	162	172	176
0.14	61	79	109	142	168	182	188
0.15	66	84	112	146	175	191	200
0.16	70	88	115	149	178	199	211
0.17	75	92	119	151	184	207	221
0.18	79	95	122	154	187	214	230
0.19	83	100	126	157	191	220	238
0.20	88	104	129	160	194	223	245
0.21	92	108	133	164	197	229	252
0.22	97	112	137	167	200	232	257
0.23	101	117	140	169	203	236	263
0.24	105	121	144	173	206	239	268
0.25	110	126	148	176	209	243	272
0.26	113	130	151	180	212	246	276
0.27	119	134	155	184	216	249	280
0.28	122	138	160	187	218	251	284
0.29	128	142	164	191	222	254	287
0.30	131	146	167	194	225	257	290
0.31	136	151	172	198	228	260	293
0.32	140	155	175	202	231	263	296
0.33	144	160	180	205	234	266	299
0.34	149	164	184	209	238	269	302
0.35	153	168	187	212	241	272	305
0.36	158	172	191	216	245	275	308
0.37	162	177	196	220	248	278	311
0.38	166	182	200	223	250	281	314
0.39	171	185	203	227	254	285	317
0.40	175	189	207	231	257	288	320

TABLE B 3/4.4-3

CHEMISTRY FACTOR FOR BASE METAL, °F

Copper, Wt-%	Nickel, Wt-% 0	0.20	0.40	0.60	0.80	1.00	1.20
0	20	20	20	20	20	20	20
0.01	20	20	20	20	20	20	20
0.02	20	20	20	20	20	20	20
0.03	20	20	20	20	20	20	20
0.04	22	26	26	26	26	26	26
0.05	25	31	31	31	31	31	31
0.06	28	37	37	37	37	37	37
0.07	31	43	44	44	44	44	44
0.08	34	48	51	51	51	51	51
0.09	37	53	58	58	58	58	58
0.10	41	58	65	65	67	67	67
0.11	45	62	72	74	77	77	77
0.12	49	67	79	83	86	86	86
0.13	53	71	85	91	96	96	96
0.14	57	75	91	100	105	106	106
0.15	61	80	99	110	115	117	117
0.16	65	84	104	118	123	125	125
0.17	69	88	110	127	132	135	135
0.18	73	92	115	134	141	144	144
0.19	78	97	120	142	150	154	154
0.20	82	102	125	149	159	164	165
0.21	86	107	129	155	167	172	174
0.22	91	112	134	161	176	181	184
0.23	95	117	138	167	184	190	194
0.24	100	121	143	172	191	199	204
0.25	104	126	148	176	199	208	214
0.26	109	130	151	180	205	216	221
0.27	114	134	155	184	211	225	230
0.28	119	138	160	187	216	233	239
0.29	124	142	164	191	221	241	248
0.30	129	146	167	194	225	249	257
0.31	134	151	172	198	228	255	266
0.32	139	155	175	202	231	260	274
0.33	144	160	180	205	234	264	282
0.34	149	164	184	209	238	268	290
0.35	153	168	187	212	241	272	298
0.36	158	173	191	216	245	275	303
0.37	162	177	196	220	248	278	308
0.38	166	182	200	223	250	281	313
0.39	171	185	203	227	254	285	317
0.40	175	189	207	231	257	288	320

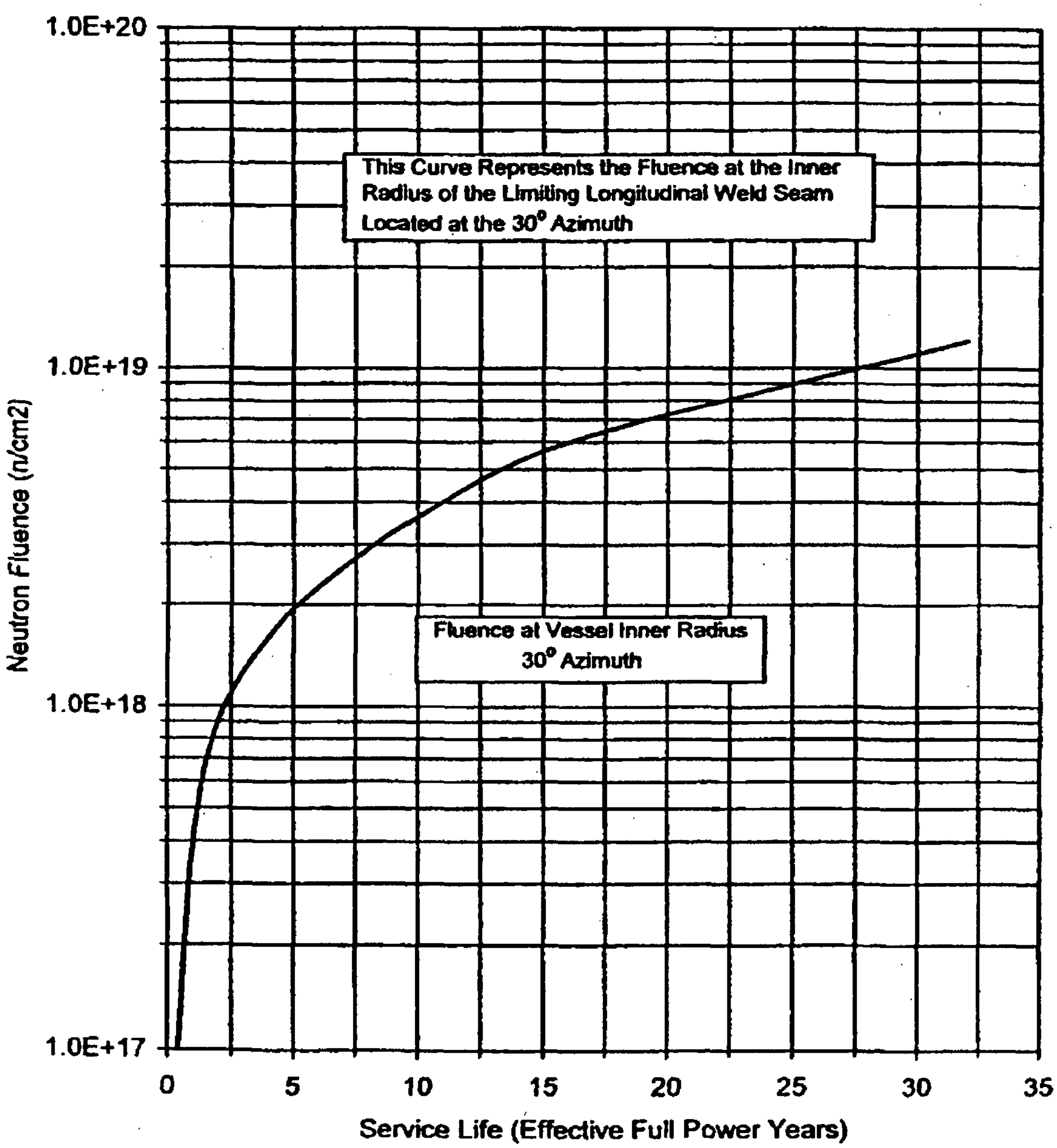
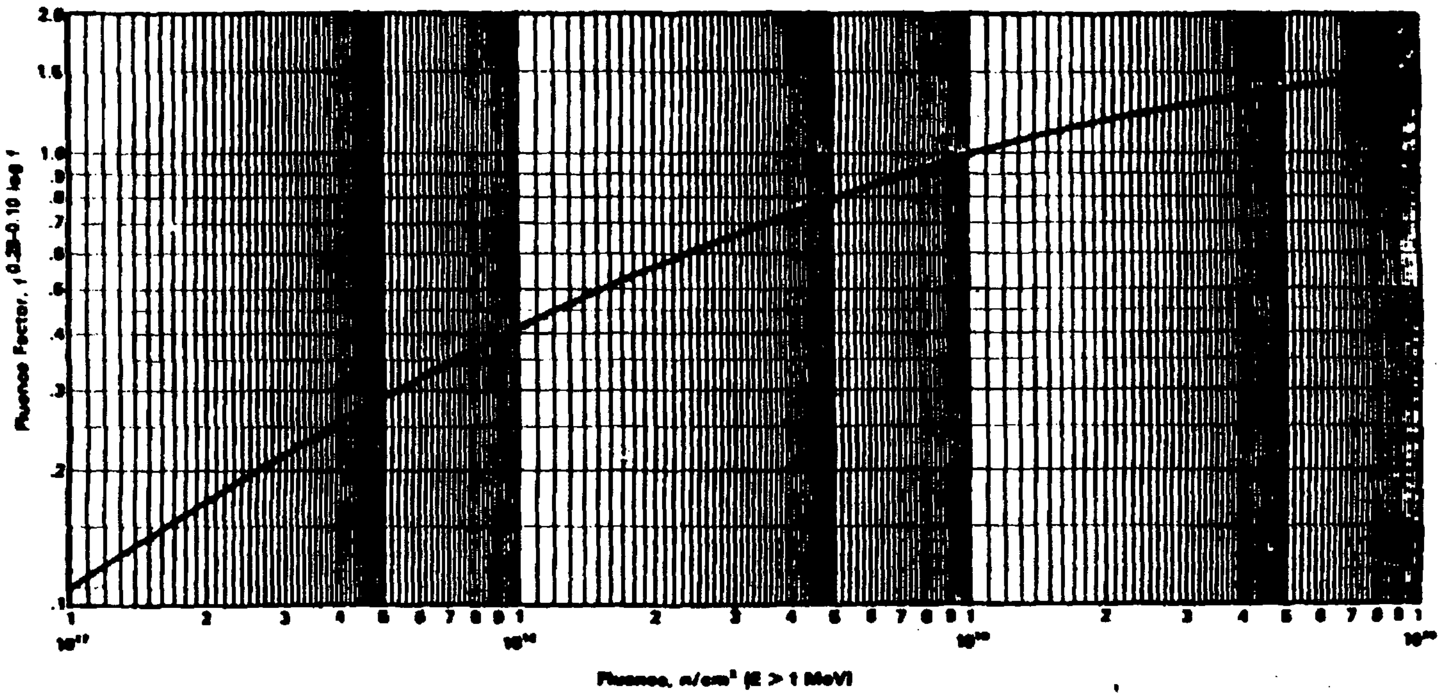


Figure B 3/4.4-1 Fast neutron fluence (E > 1 MeV) as a function of full power service life (EFPY)



Fluence Factor for use in the expression for ΔRT_{NDT}

FIGURE B 3/4.4-2

3/4.4.11 STRUCTURAL INTEGRITY

The inservice inspection and testing programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity and operational readiness of these components will be maintained at an acceptable level through the life of the plant. These programs are in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the Commission pursuant to 10 CFR Part 50.55a(g)(6)(i).

3/4.4.12 REACTOR VESSEL HEAD VENTS

Reactor Coolant System vents are provided to exhaust noncondensible gases and/or steam from the Reactor Coolant System that could inhibit natural circulation core cooling. The OPERABILITY of a reactor vessel head vent path ensures the capability exists to perform this function.

The valve redundancy of the Reactor Coolant System vent paths serves to minimize the probability of inadvertant or irreversible actuation while ensuring that a single failure vent in a valve power supply or control system does not prevent isolation of the vent path.

The function, capabilities, and testing requirements of the Reactor Coolant System Vent Systems are consistent with the requirements of Item II.B.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Correction letter dated February 15, 1990, to Amendment 86 dated January 29, 1990.

3/4.5.1 ACCUMULATORS

The OPERABILITY of each RCS accumulator ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the accumulators. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

The limits on accumulator volume, boron concentration and pressure ensure that the assumptions used for accumulator injection in the safety analysis are met.

The accumulator power operated isolation valves are considered to be "operating bypasses" in the context of IEEE Std 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required.

The limits for operation with an accumulator inoperable for any reason except an isolation valve closed minimizes the time exposure of the plant to a LOCA event occurring concurrent with failure of an additional accumulator which may result in unacceptable peak cladding temperatures. If a closed isolation valve cannot be immediately opened, the full capability of one accumulator is not available and prompt action is required to place the reactor in a mode where this capability is not required.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the accumulators is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double ended break of the largest RCS cold leg pipe downward. In addition, each ECCS subsystem provides long term core cooling capability in the recirculation mode during the accident recovery period.

ECCS SUBSYSTEMS (Continued)

With the RCS temperature below 350°F, one OPERABLE ECCS subsystem is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

The limitation for a maximum of one safety injection pump or one centrifugal charging pump to be OPERABLE and the Surveillance requirement to verify all safety injection pumps except the allowed OPERABLE safety injection pump to be inoperable below 312°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single POPS relief valve.

When running a safety injection pump with the RCS temperature less than 312 °F with the potential for injecting into the RCS and creating a mass addition pressure transient, two independent means of preventing reactor coolant system injection will be utilized. The two independent means can be satisfied by any of the following methods:
(1) A manual isolation valve locked in the closed position; or
(2) Two manual isolation valves closed; or
(3) One motor operated valve closed and its breaker de-energized and control circuit fuses removed; or
(4) One air operated valve closed and its air supply maintained in such a manner as to ensure that the valve will remain closed.

The surveillance requirements, which are provided to ensure the OPERABILITY of each component, ensure that, at a minimum, the assumptions used in the safety analyses are met and that subsystem OPERABILITY is maintained. The safety analyses make the assumptions with respect to: 1) both the maximum and minimum total system resistance, and 2) both the maximum and minimum branch injection line resistance. These resistances, in conjunction with the ranges of potential pump performance, are used to calculate the maximum and minimum ECCS flow assumed in the safety analyses.

The maximum and minimum flow surveillance requirements in conjunction with the maximum and minimum pump performance curves ensures that the assumptions of total system resistance and the distribution of that system resistance among the various paths are met.

The maximum total pump flow surveillance requirements ensure the pump runout limits of 560 gpm for the centrifugal charging pumps and 675 gpm for the safety injection pumps are not exceeded. Due to the effect of pump suction boost alignment, the runout limits for the surveillance criteria are ≤ 554 gpm for C/SI pumps, ≤ 664 gpm for SI pumps in cold leg alignment and ≤ 654 gpm for SI pumps in hot leg alignment.

The surveillance requirement for the maximum difference between the maximum and minimum individual injection line flows ensure that the minimum individual injection line resistance assumed for the spilling line following a LOCA is met.

LCO 3.0.4.b is not applicable to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystem. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

3/4.5.4 SEAL INJECTION FLOW

The Reactor Coolant Pump (RCP) seal injection flow restriction limits the amount of ECCS flow that would be diverted from the injection path following an ECCS actuation. This limit is based on safety analysis assumptions, since RCP seal injection flow is not isolated during Safety Injection (SI).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. Line pressure and flow must be known to establish the proper line resistance. Flow line resistance is determined by assuming that the RCS pressure is at normal operating pressure, and that the centrifugal charging pump discharge pressure is greater than or equal to 2430 psig. Charging pump header pressure is used instead of RCS pressure, since it is more representative of flow diversion during an accident. The additional LCO modifier, charging flow control valve full open, is required since the valve is designed to fail open. With the LCO specified discharge pressure and control valve position, a flow limit is established. This flow limit is used in the accident analysis.

A provision has been added to exempt surveillance requirement 4.0.4 for entry into MODE 3, since the surveillance cannot be performed in a lower mode. The exemption is permitted for up to 4 hours after the RCS pressure has stabilized within ± 20 psig of normal operating pressure. The RCS pressure requirement produces the conditions necessary to correctly set the manual throttle valves. The exemption is limited to 4 hours to ensure timely surveillance completion once the necessary conditions are established.

3/4.5.5 REFUELING WATER STORAGE TANK

The OPERABILITY of the RWST as a part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA.

The limits on RWST minimum volume and boron concentrations ensure that: (1) sufficient water is available within containment to permit recirculation cooling flow to the core, (2) the reactor will remain subcritical in the cold condition following a small LOCA assuming complete mixing of the RWST, RCS, and ECCS water volumes with all control rods inserted except the most reactive control assembly (ARI-1), and (3) the reactor will remain subcritical in the cold condition following a large break LOCA (break flow area > 3.0 sq. ft.) assuming complete mixing of the RWST, RCS, and ECCS water and other sources of water that may eventually reside in the sump following a LOCA with alql control rods assumed to be out (ARO). The limits on contained water volume and boron concentration also ensure a pH value of between 7.0 and 10.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.6.1 PRIMARY CONTAINMENT

3/4 6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR 100 during accident conditions.

The purpose of this surveillance requirement (4.6.1.1a) is not to perform any testing or valve manipulations, but to verify that containment isolation valves capable of being mispositioned are in their proper safety position (closed).

Physical verification (hands on verification) that these penetrations (containment isolation valves) are in the proper position is performed prior to entering Mode 4 from Mode 5 and documented in the appropriate valve line-up. Allowing the use of administrative means to verify compliance with the surveillance requirement for these valves is acceptable based on the limited access to these areas in Modes 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified in the proper position, is small.

The service water accumulator vessel and discharge valves function to maintain water filled, subcooled fluid conditions in the containment fan coil unit (CFCU) cooling loops during accident conditions. The service water accumulator vessel and discharge valves were installed to address the Generic Letter 96-06 issues of column separation waterhammer and two phase flow during an accident involving a loss of offsite power. The operability of each service water accumulator vessel and discharge valve is required to ensure the integrity of containment penetrations associated with the containment fan coil units during accident conditions. If a service water accumulator vessel does not meet the vessel surveillance requirements, or if the discharge valve response time does not meet design acceptance criteria when tested in accordance with procedures, the containment integrity requirements of the CFCU cooling loops exclusively supplied by the inoperable accumulator vessel or discharge valve are not met. Limiting Condition for Operation 3.6.1.1 is applicable, and the cooling loops for the two CFCU's exclusively supplied by the inoperable accumulator are to be removed from service and isolated to maintain containment integrity.

3/4 6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure P_a. As an added conservatism, the measured overall integrated leakage rate (Type A test) is further limited to less than or equal to 0.75 L_a or less than or equal to 0.75 L_t, as applicable, during performance of the periodic test to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the Containment Leakage Rate Testing Program.

3/4.6.1.3 CONTAINMENT AIR LOCKS

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 feet in diameter, with a door at each end. The doors are interlocked during normal operation to prevent simultaneous opening.

During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure-seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock door interlock mechanism is defeated.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident. In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day. This leakage rate is defined in 10CFR50, Appendix J as L_a = 0.1% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 47.0 psig following a DBA. The allowable leakage rate forms the basis for the acceptance criteria imposed on the surveillance requirements associated with the air locks.

Each containment air lock forms part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from containment.

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment Building Penetrations".

The ACTIONS are modified by five notes. Note (1) allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door isexpected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

Note (2) adds clarification that separate condition entry is allowed for each air lock. This is acceptable, since the required ACTIONS provide appropriate compensatory measures for each inoperable air lock. Complying with the Required Actions may allow for continued operation. A subsequent inoperable air lock is governed by condition entry for that air lock.

Notes (3) and (4) ensure that only the required ACTIONS and associated completion times of condition c. are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required ACTIONS c.1 and c.2 are the appropriate remedial actions. The exception of these Notes does not affect tracking the completion time from the initial entry into condition a., only the requirement to comply with the required ACTIONS.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note (5) directs entry into the applicable Conditions and required ACTIONS of LCO 3.6.1, "Primary Containment".

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (ACTION a.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This ACTION must be completed within 1 hour. The specified time period is consistent with the ACTIONS of LCO 3.6.1.1 that requires that containment be restored to OPERABLE status within 1 hour. OPERABILITY of the air lock interlock is not required to support the OPERABILITY of an air lock door.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour completion time (ACTION a.2). The 24 hour completion time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required ACTION a.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The completion time of once per 31 days is based on engineering judgement and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls.

ACTION a.3 allows the use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7-day restriction begins when the second air lock is discovered to be inoperable.

Containment entry may be required on a periodic basis to perform Technical Specification Surveillances and required ACTIONS, as well as other activities on equipment inside containment that are required by Technical Specifications or activities on equipment that support Technical Specification required equipment. This Note is not intended to preclude performing other activities (i.e., non-Technical Specification required activities) if the containment is entered, using the inoperable air lock, to perform an allowed entry listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

Because of ALARA considerations, ACTION a.3 also allows air lock doors located in high radiation areas to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

With an air lock interlock mechanism inoperable in one or more air locks, the required ACTIONS and associated completion times are consistent with those specified in Condition a. In addition, ACTION b.3 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock). In addition, ACTION b.3 allows air lock doors located in high radiation areas to be verified locked closed by use of administrative means.

ACTION c.1 requires that with one or more air locks inoperable for reasons other than those described in condition a. or b., action must be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required ACTION c.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour completion time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour completion time. This completion time begins at the time that the air lock is discovered to be inoperable. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

If the inoperable containment air lock cannot be restored to OPERABLE status within the required completion time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least Hot Standby within 6 hours and to Cold Shutdown within the following 30 hours. The allowed completion times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Maintaining containment airlocks OPERABLE requires compliance with the leakage rate test requirements of 10CFR50, Appendix J, as modified by approved exemptions. This Surveillance Requirement reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The frequency is required by Appendix J, as modified by approved exemptions. Thus, the provision of Specification 4.0.2 (which allows frequency extensions) does not apply.

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when the containment air lock door is opened, this test is only required to be performed upon entering or exiting a containment air lock but is not required more frequently than every six months. The six-month frequency is based on engineering judgement and is considered adequate in view of other indications of door and interlock mechanism status available to operations personnel.

3/4.6.1.4 INTERNAL PRESSURE

The limitations on containment internal pressure ensure that: 1) the containment structure is prevented from exceeding its design negative pressure differential with respect to the outside atmosphere of 3.5 psig, and 2) the containment peak pressure does not exceed the design pressure of 47 psig during the limiting pipe break conditions. The pipe breaks considered are LOCA and steam line breaks.

The limit of 0.3 psig for initial positive containment pressure is consistent with the accident analyses initial conditions.

The maximum peak pressure expected to be obtained from a LOCA or steam line break event is ≤ 47 psig.

3/4.6.1.5 AIR TEMPERATURE

The limitations on containment average air temperature ensure that the overall containment average air temperature does not exceed the initial temperature condition assumed in the accident analysis for a LOCA or steam line break. In order to determine the containment average air temperature, an average is calculated using measurements taken at locations within containment selected to provide a representative sample of the overall containment atmosphere.

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the containment will withstand the design pressure. The visual inspections of the concrete and liner and the Type A leakage test, both in accordance with the Containment Leakage Rate Testing Program, are sufficient to demonstrate this capability.

(Note that the elements of 3/4.6.1.7 were RELOCATED to 3/4 6.3 by LCR S06-06)

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the containment spray system, when operated in conjunction with the Containment Cooling System, ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

The containment spray system also provides a mechanism for removing iodine from the containment atmosphere and therefore the time requirements for restoring an inoperable spray system to OPERABLE status have been maintained consistent with that assigned other inoperable ESF equipment.

Normal plant operation and maintenance practices are not expected to trigger surveillance requirement 4.6.2.1.d. Only an unanticipated circumstance would initiate this surveillance, such as inadvertent spray actuation, a major configuration change, or a loss of foreign material control when working within the affected boundary of the system. If an activity occurred that presents the potential of creating nozzle blockage, an evaluation would be performed by the engineering organization to determine if the amount of nozzle blockage would impact the required design capabilities of the containment spray system. If the evaluation determines that the containment spray system would continue to perform its design basis function, then performance of the air or smoke flow test would not be required. If the evaluation cannot conclusively determine the impact to the containment spray system, then the air or smoke flow test would be performed to determine if any nozzle blockage has occurred.

3/4.6.2.2 SPRAY ADDITIVE SYSTEM

The OPERABILITY of the spray additive system ensures that sufficient NaOH is added to the containment spray in the event of a LOCA. The limits on NaOH volume and concentration, ensure that 1) the iodine removal efficiency of the spray water is maintained because of the increase in pH value, and 2) corrosion effects on components within containment are minimized. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics. These assumptions are consistent with the iodine removal efficiency assumed in the accident analyses.

3/4.6.2.3 CONTAINMENT COOLING SYSTEM

The OPERABILITY of the containment cooling system ensures that adequate heat removal capacity is available when operated in conjunction with the containment spray systems during post-LOCA conditions.

The surveillance requirements for the service water accumulator vessels ensure each tank contains sufficient water and nitrogen to maintain water filled, subcooled fluid conditions in three containment fan coil unit (CFCU) cooling loops in response to a loss of offsite power, without injecting nitrogen covergas into the containment fan coil unit loops assuming the most limiting single failure. The surveillance requirement for the discharge valve response time test ensures that on a loss of offsite power, each discharge valve actuates to the open position in accordance with the design to allow sufficient tank discharge into CFCU piping to maintain water filled, subcooled fluid conditions in three CFCU cooling loops, assuming the most limiting single failure.

3/4.6.3 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The opening of locked or sealed closed containment isolation valves (penetration flow paths) on an intermittent basis under administrative control includes the following considerations: (1) stationing a dedicated individual, who is in constant communication with the control room, at the valve controls, (2) instructing this individual to close these valves in an accident situation, and (3) assuring that the environmental conditions will not preclude access to close the valves and that this action will prevent the release of radioactivity outside the containment.

The main steam isolation valves (MSIVs) fulfill their containment isolation function as remote-manual containment isolation valves. The automatic closure of the MSIVs is not required for containment isolation due to having a closed system inside containment. The remote-manual containment isolation function of the MSIVs can be accomplished through either the use of the hydraulic operator or when the MSIV has been tested in accordance with surveillance requirement 4.7.1.5 the steam assist closure function can be credited.

Surveillance Requirement (SR) 4.6.3.3 only applies to the MS7 (Main Steam Drain) valves and the MS18 (Main Steam Bypass) valves. The MS167 (Main Steam Isolation) valves are tested for main steam isolation purposes by SR 4.7.1.5. For containment isolation purposes, the MS167s are tested as remote/manual valves pursuant to Specification 4.0.5.

containment purge supply and exhaust penetrations performs no containment integrity function in MODES 1-4; these valves operate during shutdown for normal system purging and containment closure when the blind flanges are removed.

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions. Either recombiner unit is capable of controlling the expected hydrogen generation associated with 1) zirconium-water reactions, 2) radiolytic decomposition of water, and 3) corrosion of metals within containment. These hydrogen control systems are consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA," March 1971.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% of its design pressure of 1085 psig during the most severe anticipated system operational transient. The MSSVs also provide protection against overpressurization of the Reactor Coolant Pressure Boundary by providing a heat sink for the removal of energy from the Reactor Coolant System if the preferred heat sink is not available. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is 16.66×10^6 lbs/hr which is 110.4% of the maximum calculated steam flow of 15.08×10^6 lbs/hr at 100% RATED THERMAL POWER. A minimum of 2 OPERABLE safety valves per OPERABLE steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-2.

STARTUP and/or POWER OPERATION is allowable with inoperable safety valves within the limitations of the ACTION requirements on the basis of the reduction in secondary steam flow associated with the required reduction of RATED THERMAL POWER. The acceptable power level (in percent RATED THERMAL POWER) for operation with inoperable safety valves was determined by performing explicit transient analysis.

The events that challenge the relief capacity of the safety valves are those resulting in decreased heat removal capability. In this category of events, a loss of external electrical load and/or turbine trip is the limiting anticipated operational occurrence. A series of cases was analyzed for this transient covering up to two inoperable safety valves on each steam generator. The results of these cases were used to determine a maximum thermal power level from which the event could be initiated without exceeding the primary and secondary side design pressure limits. Thus, the maximum allowed power level as a function of the number of inoperable MSSVs on any steam generator is presented in Table 3.7-1. Note that the power level values presented on this table are the direct inputs into the transient analysis cases and do not include any allowance for calorimetric error. Actual power level reductions must include calorimetric uncertainty and other allowances for operating margin as deemed necessary.

Specific accident analyses for RCCA Bank Withdrawal at Power scenarios demonstrate that adequate safety valve relief capacity exist with up to two inoperable safety relief valves on each steam generator. These cases demonstrate that the reactor trip on OTDT along with the relief from the available main steam safety valves is sufficient to meet secondary side pressurization limits.

For three inoperable main steam safety valves in one or more steam generators, thermal reactor power must be reduced in conjunction with a reduction in the Power Range Neutron Flux High trip setpoint to prevent overpressurization of the main steam system.

The transient analysis assumes that the MSSVs will start to open at the lift setpoint with 3% allowance for setpoint tolerance. In addition, the analysis accounts for accumulation by including a 5 psi ramp for the valve to reach its fully open position. Inoperable MSSVs are assumed to be those with the lowest lift setting. Surveillance testing as covered in Table 3.7-4 allows a ± 3% lift setpoint tolerance. However, to allow for drift during subsequent operation, the valves must be reset to within ± 1% of the lift setpoint following testing.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the auxiliary feedwater system ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of offsite power.

Verifying that each Auxiliary Feedwater (AFW) pump's developed head at the flow test point is greater than or equal to the required minimum developed head ensures that the AFW pump performance has not degraded during the cycle, and that the assumption made in the accident analysis remain valid. Flow and differential head are normal tests of centrifugal pump performance required by Section XI of the ASME Code. Because it is undesirable to introduce cold AFW into the steam generators while operating, the test is performed on recirculation flow. This test confirms one point on the pump design curve (head vs flow curve), and is indicative of pump performance. Inservice testing confirms pump operability, trends performance and detects incipient failures by indication of pump performance.

The flow path to each steam generator is ensured by maintaining all manual maintenance valves locked open. A spool piece consisting of a length of pipe may be used as an equivalent to a locked open manual valve. The manual valves in the flow path are: 2AF1, 21AF3, 22AF3, 23AF3, 21AF10, 22AF10, 23AF10, 24AF10, 21AF20, 22AF20, 23AF20, 24AF20, 21AF22, 22AF22, 23AF22, 24AF22, 21AF86, 22AF86, 23AF86, and 24AF86.

LCO 3.0.4.b is not applicable to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

3/4.7.1.3 AUXILIARY FEED STORAGE TANK

The OPERABILITY of the auxiliary feed storage tank with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 8 hours with steam discharge to the atmosphere concurrent with total loss of offsite power. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the accident analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the main steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

If the closure time of the main steam isolation valve (MSIV) during technical specification surveillance testing (performed at a Steam Generator pressure between 800 psig and 1015 psig) is 5.0 seconds or less and the engineered safety feature response time (including valve closure time) for the steam line isolation (MSI) signal (Table 3.3-5) is 5.5 seconds or less, then assurance is provided that MSI occurs within 12 seconds under accident conditions, where Steam Generator pressure may be lower. This method of testing assures that for main steam line ruptures that are initiated from Modes 1-3 conditions that generate a MSI signal via automatic or manual initiation and have adequate steam line pressure to close, the main steam lines isolate within the time required by the accident analysis. Fast closure of the MSIVs is assured at a minimum steam pressure of 170 psia. However, the MSIV will still close via the steam assist function between 118 - 170 psia with slightly greater closure times. For main steam line ruptures that receive an automatic or manual signal for MSI and do not have adequate steam pressure to close the MSIVs (less than 118 psia), the event does not require MSIV closure to provide protection to satisfy design basis requirements (e.g., minimum DNBR remains above the minimum DNBR limit value and peak containment pressure remains below 47 psig).

Testing for SR 4.7.1.5 is performed prior to opening the MSIVs for power operation. During testing, only one valve is opened at a time, with the other three valves remaining closed in the safe position, ensuring isolation capability is maintained. In the event of a steam line rupture, a postulated failure of the tested valve in the open position would result in the blowdown of a single steam generator since the remaining three MSIVs are closed. Failure of a single MSIV to close is consistent with the accident analysis assumptions for a major secondary system pipe rupture (UFSAR Section 15.4.2).

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70°F and 200 psig are based on average steam generator impact values taken at 10°F and are sufficient to prevent brittle fracture.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the component cooling water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The component cooling water system (CCW) consists of two safeguards mechanical trains supplied by three pumps powered from separate vital buses. This complement of equipment assures adequate redundancy in the event of a single active component failure during the injection phase. Operability of the CCW system exists when both mechanical trains and all three CCW pumps are operable.

3/4.7.4 SERVICE WATER SYSTEM

The OPERABILITY of the service water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.5 FLOOD PROTECTION

The limitation on flood protection ensures that facility protective actions will be taken and operation will be terminated in the event of flood conditions. The limit of elevation 10.5' Mean Sea Level is based on the elevation above which facility flood control measures are required to provide protection to safety-related equipment.

3/4.7.6 CONTROL ROOM EMERGENCY AIR CONDITIONING SYSTEM

The OPERABILITY of the control room emergency air conditioning system (CREACS) ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all credible accident conditions.

The CREACS is a shared system between Unit 1 and 2 supplying a common Control Room Envelope (CRE). During emergency operation following receipt of a Safety Injection or High Radiation actuation signal, for areas inside the CRE, one 100% capacity fan in each Unit's CREACS will operate in a pressurization mode with a constant amount of outside air supplied for continued CRE pressurization to 1/8" water gauge. One fan from each train will automatically start upon receipt of an initiation signal, with one fan in each train in standby. A failure of one fan will result in the standby fan automatically starting.

Each CREACS train has two 100% capacity fans, such that any one of the four fans is sized to provide the required flow for CRE pressurization to 1/8" water gauge positive pressure within the common CRE during an emergency.

A failure of one CREACS filtration train requires manual actions to properly reposition dampers in support of single filtration train operation.

To minimize control room radiological doses, the CREACS outside air is supplied from the non-accident unit's emergency air intake through the cross-connected supply duct (as determined by which unit received an accident signal). Outside air is mixed with recirculated air, passed through each CREACS filter bank (pre-filter, HEPA filter, and charcoal filter) and cooling coil, and distributed to the common CRE.

CREACS will be manually initiated in the recirculation mode only in the event of a fire outside the CRE, a toxic chemical release, delivery of Ammonium Hydroxide or testing.

A significant contributor to this system's OPERABILITY are the dampers which are required to actuate to their correct positions. The following dampers are associated with the respective LCO*:

a.1 Fan outlet dampers: 1(2)CAA15 and 1(2)CAA16

These dampers ensure that the flow path for CREACS is operable and are required to open upon CREACS initiation. The associated fan outlet damper will open on fan operation.

a.4 Return air isolation damper: 1(2)CAA17

When aligned for single train operation, the associated air return isolation damper will be administratively controlled in the open position.

b. Other dampers required for automatic operation in the pressurization or recirculation modes:

Control Area Air Conditioning System (CAACS) outside air intake isolation dampers: 1(2)CAA40, 1(2)CAA41, 1(2)CAA43 and 1(2)CAA45

The normally open outside air intake dampers 1(2)CAA40 and inlet plenum isolation dampers 1(2)CAA43 will be closed under emergency conditions. The normally closed outside air intake dampers 1(2)CAA41 and inlet plenum isolation dampers 1(2)CAA45 are normally closed and remain closed under emergency conditions.

Control Area Air Conditioning System (CAACS) exhaust isolation dampers: 1(2)CAA18 and 1(2)CAA19.

These dampers are normally closed and are required to remain closed to prevent inleakage from the outside environment in the event of a toxic release.

Control Room Emergency Air Conditioning System (CREACS) air intake dampers: 1(2)CAA48, 1(2)CAA49, 1(2)CAA50 and 1(2)CAA51

CREACS outside air intake dampers are maintained closed during normal and recirculation operation and are opened automatically upon initiation of CREACS pressurization. The control logic will automatically open the CREACS air intake dampers farthest from the radiation source based upon which Unit's Solid State Protection System (SSPS) or Radiation Monitoring System (RMS) signal is received.

* Operability of the CRECS requires that each of the Unit 1 dampers are also operable

CAACS and CREACS interface isolation dampers: 1(2)CAA14 and 1(2)CAA20

These two dampers are normally open and do not have associated redundant dampers. These dampers serve a boundary function by isolating the CREACS from the CAACS during emergency operation of the CREACS.

Note: Dampers 1(2)CAA5, CAACS recirculation damper will receive an accident alignment signal to ensure proper accident configuration of CAACS. This damper, however, is not required for the OPERABILITY of CREACS as defined in the LCO.

The control room envelope is considered intact and able to support operation of the CREACS when the emergency air conditioning system is capable of maintaining a 1/8" water gauge positive pressure with the control room boundary door(s) closed.

Filter testing will be in accordance with the applicable sections of ANSI N510 (1975) with the exception that laboratory testing of activated carbon will be in accordance with ASTM D3803 (1989). The acceptance criteria for the laboratory testing of the carbon adsorber is determined by applying a minimum safety factor of 2 to the charcoal filter removal efficiency credited in the design basis dose analysis as specified in Generic Letter 99-02.

TS Surveillance Requirement verifies that each fan is capable of operating for at least 15 minutes by initiating flow through the HEPA filter and charcoal adsorber train(s) to ensure that the system is available in a standby mode.

Each CAACS normal air intake ductwork will have an additional radiation detector channel installed for a total of two detectors per intake. The two detector channels from Unit 1 and Unit 2 CAACS air intake provide input to common radiation monitor processors. Each radiation monitor processor (one for 1R1B-1/1R1B-2 and one for 2R1B-1/2R1B-2) provides a signal to initiate CREACS in the pressurization mode should high radiation be detected. A minimum of one out of two detectors in either intake will initiate the pressurization mode. With two detector channels inoperable on a Unit, operation may continue as long as CREACS is placed inservice in the pressurization or recirculation mode. Pressurization mode will be initiated after 7 days with one inoperable detector. Radiological releases during a fuel handling accident while operating in the recirculation mode could result in unacceptable radiation levels in the CRE since the automatic initiation capability has been defeated for high radiation due to isolation of the detectors. Therefore, movement of irradiated fuel assemblies or Core Alterations at either Unit will not be permitted when in the recirculation mode.

Immediate action(s), in accordance with the LCO Action Statements, means that the required action should be pursued without delay and in a controlled manner.

The OPERABILITY of this system in conjunction with control room design features provides adequate radiation protection to permit access to and occupancy of the Salem control room for the entire duration of the postulated accident with no person in the control room receiving radiation exposure that exceeds 5 rem TEDE. This limitation is consistent with the requirements of Regulatory Guide 1.183.

3/4.7.7 AUXILIARY BUILDING VENTILATION SYSTEM

The Auxiliary Building Ventilation System (ABVS) consists of two major subsystems. They are designed to control Auxiliary Building temperature during normal and emergency modes of operation, to maintain slightly negative pressure in the building to prevent unmonitored leakage out of the building and to contain Auxiliary Building airborne contamination (by maintaining slightly negative pressure) during Loss of Coolant Accidents (LOCA). The two subsystems are:

1. A once through filtration exhaust system, designed to contain particulate and gaseous contamination and prevent it from being released from the building in accordance with 10CFR20 (no credit is taken for post-accident filtration), and

2. A once through air supply system, designed to deliver outside air into the building to maintain building temperatures and negative pressure within acceptable limits. For the purposes of satisfying the Technical Specification LCO, one supply fan must be administratively removed from service such that the fan will not auto-start on an actuation signal; however, the supply fan must be OPERABLE with the exception of this administrative control.

These systems operate during normal and emergency plant modes. Additionally, the system provides a flow path for containment purge supply and exhaust during Modes 5 and 6. Either the Containment Purge System or the Auxiliary Building Ventilation System with suction from the containment atmosphere, with associated radiation monitoring will be available whenever movement of irradiated fuel is in progress in the containment building and the equipment hatch is open. If for any reason, this ventilation requirement can not be met, movement of fuel assemblies within the containment building shall be discontinued until the flow path(s) can be reestablished or close the equipment hatch and personnel airlocks.

Appropriate filtration surveillances are contained in the Updated Final Safety Analysis Report (UFSAR) Section 9.4.2.4, Test and Inspections. Auxiliary Building exhaust air filtration system functionality is not required to meet LCO 3.7.7.

The ventilation exhaust consists of three 50% capacity fans that are powered from vital buses. The fans are designed for continuous operation, to control the Auxiliary Building pressure at -0.10" Water Gauge with respect to atmosphere.

The ventilation supply consists of two 100% capacity fans that are powered from vital buses, and distribute outdoor air to the general areas and corridors of the building through associated ductwork.

3/4.7.7 AUXILIARY BUILDING EXHAUST AIR FILTRATION SYSTEM (cont'd)

AUXILIARY BUILDING VENTILATION ALIGNMENT MATRIX
NORMAL VENTILATION (Normal plant operations)*

Any two of the three exhaust fans and either of the two supply fans.

* The normal alignment is two exhaust fans and one supply fan. During cooler seasons, and with the absence of the system heating coils, it may be required to limit the amount of colder outside air entering the building. In this case, it is acceptable to secure both supply fans from operation and reduce the number of operating exhaust fans to one. There is sufficient capacity with the single exhaust fan to maintain the negative pressure within the auxiliary building boundary.

EMERGENCY VENTILATION (Emergency plant operations)

At least two of the three exhaust fans and either one of the two supply fans.

Note: During a Safety Injection (SI) all three exhaust fans and one of the supply fans will start. This is acceptable and will maintain the boundary pressure while supplying the required cooling to the building. Should access/egress become difficult with the three exhaust fans running, one of the exhaust fans should be secured.

OPERABILITY of the Auxiliary Building Ventilation System ensures that air, which may contain radioactive materials leaked from ECCS equipment following a LOCA, is monitored prior to release from the plant via the plant vent. Operation of this system and the resultant effect on offsite and control room dose calculations was assumed in the accident analyses. ABVS is discussed in UFSAR Section 9.4.2.

3/4.7.8 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4.7.9 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety related systems and then only if their failure or failure of the system on which they were installed, would have no adverse effect on any safety-related system.

A list of individual snubbers required to be operable per the technical specifications with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the Station Operations Review Committee. The determination shall be based on the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.) and the recommendations of Regulatory Guide 8.8 and 8.10. The addition or deletion of any snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to systems. Therefore, the required inspection interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. The inspections are performed for each category of snubbers. The snubbers are categorized by accessibility (i.e., accessible or inaccessible during reactor operation). The next visual inspection for each category may be twice, the same, or reduced by as much as two-thirds of the previous inspection interval. This interval depends on the number of unacceptable snubbers found in proportion to the total number of snubbers in each category from the most recent inspection. Intervals may be increased up to 48 months if few unacceptable snubbers are found in these inspections. The visual inspection interval will not exceed 48 months. However, as for all surveillance activities, unless otherwise noted, allowable tolerances of 25% are applicable for snubbers. Table 4.7-3 establishes three limits for determining the next visual inspection interval corresponding to the population of each category of snubbers. For a category that differs from the representative sizes provided, the values for the next inspection interval may be found by interpolation from the limits provided in Columns A, B, and C. Where the limit for unacceptable snubbers in Columns A, B, or C is determined by interpolation and includes a fractional value, the limit may be reduced to the next lower integer. The first inspection interval determined using Table 4.7-3 shall be based upon the previous inspection interval as established by the requirements in effect before amendment (142). Any inspection whose results require a shorter inspection interval will override the previous schedule.

SNUBBERS (Continued)

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection or are similarly located or exposed to the same environmental conditions, such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested during plant shutdowns at 18-month intervals. Observed failures of these sample snubbers shall require functional testing of additional units.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance program.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc...). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

3/4.7.10 CHILLED WATER SYSTEM - AUXILIARY BUILDING SUBSYSTEM

The OPERABILITY of the chilled water system ensures that the chilled water system will continue to provide the required normal and accident heat removal capability for the control room area, relay rooms, equipment rooms, and other safety related areas. Verification of the actuation of each automatic valve on a Safeguards Initiation signal includes actuation following receipt of a Safety Injection signal.

Removal of non-essential heat loads from the chilled water system in the event one chiller is inoperable ensures the remaining heat loads are within the heat removal capacity of the two operable chillers.

Removal of non-essential heat loads from the chilled water system in the event two chillers are inoperable and aligning the CREACs to the maintenance mode ensures the remaining heat loads are within the heat removal capacity of the operable chiller.

During chiller testing, operator actions can take the place of automatic actions.

During Modes 5 and 6 and during movement of irradiated fuel assemblies, chilled water components do not have to be considered inoperable solely on the basis that the backup emergency power source, diesel generator, is inoperable. This is consistent with Technical Specification 3.8.1.2 which only requires two operable diesel generators.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. Region 1, with 300 storage positions, is designed to accommodate new fuel with a maximum enrichment of 4.25 wt% U-235. Unirradiated and irradiated fuel with initial enrichments up to 5.0 wt% U-235 can also be stored in Region 1 with some restrictions. These restrictions are stated in TS 3/4.7.12. Region 2, with 1332 storage positions, is designed to accommodate unirradiated and irradiated fuel with stricter controls as compared to Region 1. These controls are also stated in TS 3/4.7.12.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the USNRC letter of April 14, 1978, to all Power Reactor Licensees - OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications (Accession # 7910310568) allows credit for soluble boron under other abnormal or accident conditions, consistent with postulated accident scenarios. For example, the most severe accident scenario is associated with the abnormal location of a fresh fuel assembly of 5.0 wt% enrichment which could, in the absence of soluble poison, result in exceeding the design reactivity limitation (k_{eff} of 0.95). This could occur if a fresh fuel assembly of 5.0 wt% enrichment were to be inadvertently loaded into a Region 1 or Region 2 storage cell otherwise filled to capacity. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Calculations for the worst case configuration confirmed that 800 ppm soluble boron (includes an appropriate allowance for boron concentration measurement uncertainty)is adequate to compensate for a mis-located fuel assembly. Subcriticality of the MDR with no movement of assemblies is achieved without credit for soluble boron and by controlling the location of each assembly in accordance with TS 3/4.7.12. Prior to movement of an assembly, it is necessary to verify the fuel storage pool boron concentration is within limit in accordance with TS 3/4.7.11.

Most postulated abnormal conditions or accidents in the spent fuel pool do not result in an increase in the reactivity of either MDR region. For example, an event that results in an increase in spent fuel pool temperature or a decrease in water density will not result in a reactivity increase. An event that results in the spent fuel pool cooling down below normal conditions does not impact the criticality analysis since the analysis assumes a water temperature of 4°C. This assures that the reactivity will always be lower over the expected range of water temperatures.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION (continued)

However, accidents can be postulated that could increase the reactivity. This increase in reactivity is unacceptable with unborated water in the storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool prevents criticality exceeding limits in both regions. The postulated accidents are basically of three types. The first type of postulated accident is an abnormal location of a fuel assembly, the second type of postulated accident is associated with lateral rack movement, and the third type of postulated accident is a dropped fuel assembly on the top of the rack. The dropped fuel assembly and the lateral rack movement have been previously shown to have negligible reactivity effects ($<0.0001\ \delta k$). The misplacement of a fuel assembly could result in Keff exceeding the 0.95 limit. However, the negative reactivity effect of a minimum soluble boron concentration of 600 ppm compensates for the increased reactivity caused by any of the postulated accident scenarios. The accident analyses are summarized in the FSAR Section 9.1.2.

The determination of 600 ppm has included the necessary tolerances and uncertainties associated with fuel storage rack criticality analyses. To ensure that soluble boron concentration measurement uncertainty is appropriately considered, additional margin is incorporated into the limiting condition for operation. As such, increasing the minimum required boron concentration in the fuel storage pool to 800 ppm conservatively covers the expected range of boron reactivity worth along with allowances associated with boron measurements.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). The fuel storage pool boron concentration is required to be greater than or equal to 800 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential critical accident scenarios. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the fuel storage pool.

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool, until a complete spent fuel storage pool verification has been performed following the last movement of fuel assemblies in the spent fuel storage pool. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

3/4.7.11 FUEL STORAGE POOL BORON CONCENTRATION (continued)

The Required Actions are modified indicating that LCO 3.0.3 does not apply. Storage of fuel assemblies and the boron concentration in the spent fuel storage pool are independent of reactor operation. Therefore TS 3/4 3.7.11 and TS3/ 4 3.7.12 include the exception to LCO 3.0.3 to preclude an inappropriate reactor shutdown. When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Alternatively, beginning a verification of the fuel storage pool fuel locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving fuel assemblies in the spent fuel pool while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving fuel assemblies in the spent fuel pool while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. Region 1, with 300 storage positions, is designed to accommodate new fuel with a maximum enrichment of 4.25 wt% U-235. Unirradiated and irradiated fuel with initial enrichments up to 5.0 wt% U-235 can also be stored in Region 1 with some restrictions. These restrictions are stated in TS 3/4.7.12. Region 2, with 1332 storage positions, is designed to accommodate unirradiated and irradiated fuel with stricter controls as compared to Region 1. These controls are also stated in TS 3/4.7.12.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the USNRC letter of April 14, 1978, to all Power Reactor Licensees - OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications (Accession # 7910310568) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenario is associated with the abnormal location of a fresh fuel assembly of 5.0 wt% enrichment which could, in the absence of soluble poison, result in exceeding the design reactivity limitation (k_{eff} of 0.95). This could occur if a fresh fuel assembly of 5.0 wt% enrichment were to be inadvertently loaded into a Region 1 or Region 2 storage cell otherwise filled to capacity, for any of the configurations. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Calculations for the worst case configuration confirmed that 800 ppm soluble boron (includes an appropriate allowance for boron concentration measurement uncertainty) is adequate to compensate for a mis-located fuel assembly. Safe operation of the MDR with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with TS 3/4.7.12. Prior to movement of an assembly into a fuel assembly storage location in Region 1 or Region 2, it is necessary to perform SR 4.7.11 and either SR 4.7.12.1 or SR 4.7.12.2. In summary, before moving an assembly into the storage racks it is necessary to:

- validate that its final location meets the criticality requirements;
- and since there is a potential to misload the assembly, we need to ensure that the Fuel Storage Pool boron concentration is greater than the minimum required to preclude exceeding criticality limits prior to moving.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

3/4.7.12 FUEL ASSEMBLY STORAGE IN THE SPENT FUEL POOL (CONTINUED)

The restrictions on the placement of fuel assemblies within the spent fuel pool in accordance with TS 3/4.7.12, in the accompanying LCO, ensures the k_{eff} of the spent fuel storage pool will always remain < 0.95, assuming the pool to be flooded with unborated water.

This LCO applies whenever any fuel assembly is stored in Region 1 or Region 2 of the fuel storage pool.

The Required Actions are modified indicating that LCO3.0.3 does not apply. Storage of fuel assemblies and the boron concentration in the spent fuel storage pool are independent of reactor operation. Therefore TS 3/4.3.7.11 and TS 3/4.3.7.12 include the exception to LCO 3.0.3 to preclude an inappropriate reactor shutdown. When the configuration of fuel assemblies stored in Region 1 or Region 2 of the spent fuel storage pool is not in accordance with TS 3/4.7.12, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with TS 3/4.7.12. If unable to move fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

The SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with TS 3/4.7.12 in the accompanying LCO.

3/4.8.1 and 3/4.8.2 A.C. SOURCES AND ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility, and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix "A" to 10 CFR Part 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the accident analyses and are based upon maintaining at least two independent sets of onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of one onsite A.C. source.

When a system or component is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may still be considered OPERABLE, provided the appropriate Actions of 3.8.1.1.a.2, b.2 or d.2 are satisfied.

Action 3.8.1.1.a.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required systems. Failure of a single offsite circuit will generally not, by itself, cause any equipment to lose normal AC power. Action 3.8.1.1.b.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. Action 3.8.1.1.d.2, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions.

These systems are powered from the independent AC electrical power train. However, redundant required systems or components credited by this specification are not necessarily powered from AC electrical sources. For example, the single train turbine-driven auxiliary feedwater pump is redundant to the two motor-driven pumps. Redundant required system or component failures consist of inoperable equipment associated with a train, redundant to the train that has an inoperable DG or offsite power.

LCO 3.0.4.b is not applicable to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG. The provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The completion time for these actions is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This completion time also allows for an exception to the normal "time zero" for beginning the allowed outage time clock, starting only on discovery that both:

a. One train has no offsite power supplying its loads, one DG is inoperable or two required offsite circuits are inoperable; and

b. A required system or component on the other train is inoperable.

If at any time during these conditions a redundant required system or component subsequently becomes inoperable, this completion time begins to be tracked. Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System, or one required DG inoperable, coincident with one or more inoperable required support or supported systems or components that are associated with the other train that has power, results in starting the completion times for the Action. The specified time is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE AC supplies (one offsite circuit and three DGs for Condition (a), two offsite circuits and two DGs for Condition (b), or three DGs for Condition (d)) are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required system or component's function may have been lost; however, function has not been lost. The completion time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required system or component. Additionally, the completion time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The completion time for Condition d (loss of both offsite circuits) is reduced to 12 hours from that allowed for one train without offsite power (Action 3.8.1.1.a.2). The rationale is that Regulatory Guide 1.93 allows a completion time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required system or component failure exists, this assumption is not the case, and a shorter completion time of 12 hours is appropriate.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that 1) the facility can be maintained in the shutdown or refueling condition for extended time periods and 2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The Applicability of specifications 3.8.2.2, 3.8.2.4, and 3.8.2.6 includes the movement of irradiated fuel assemblies. This will insure adequate electrical power is available for proper operation of the fuel handling building ventilation system during movement of irradiated fuel in the spent fuel pool.

An offsite circuit would be considered inoperable if it were not available to one required train. Although two trains are required by LCOs 3.8.2.2 and 3.8.2.4, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and irradiated fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's actions.

With the offsite circuit or diesel generator not available to all required trains, the option exists to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With both required diesel generators inoperable, the minimum required diversity of AC power sources is not available. Therefore, it is required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required shutdown margin or boron concentration. Suspending positive reactivity additions that could result in failure to meet the minimum shutdown margin or boron concentration limit is required to assure continued safe operation.

The Surveillance Requirements for demonstrating the OPERABILITY of the diesel generators are based upon the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977. Regulatory Guide 1.108 criteria for determining and reporting valid tests and failures, and accelerated diesel generator testing, have been superseded by implementation of the Maintenance Rule for the diesel generators per 10CFR50.65. In addition to the Surveillance Requirements of 4.8.1.1.2, diesel preventative maintenance is performed in accordance with procedures based on manufacturer's recommendations with consideration given to operating experience.

The minimum voltage and frequency stated in the Surveillance Requirements (SR) are those necessary to ensure the Emergency Diesel Generator (EDG) can accept Design Basis Accident (DBA) loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential in establishing EDG OPERATILITY, but a time constraint is not imposed. The lack of a time constraint is based on the fact that a typical EDG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. In lieu of a time constraint in the SR, controls will be provided to monitor and trend the actual time to reach stable operation within the band as a means of ensuring there is no voltage regulator or governor degradation that could cause an EDG to become inoperable.

"Standby condition" for the purpose of defining the condition of the engine immediately prior to starting for surveillance requirements requires that the lube oil temperature be between 100 °F and 170 °F. The minimum lube oil temperature for an OPERABLE diesel is 100 °F.

The thirteen second time requirement for the Emergency Diesel Generator to reach rated voltage and frequency was originally based on a Westinghouse assumption of fifteen seconds that included the delay time between the occurrence of the incident and the application of electrical power to the first sequenced safeguards pump (BURL-3011, dated November 13, 1974) and included an instrument response time of two seconds (BURL-1531, dated July 27, 1970). The times specified in UFSAR Section 15.4 bound the thirteen seconds specified in the TS.

The narrower band for frequency specified for testing performed in steady state isochronous operation will ensure the EDG will not be run in an overloaded condition (steady state) during accident conditions. Steady state is assumed to be achieved after one minute of operation in the isochronous mode with all required loads sequenced on the bus.

The narrower band for steady state voltage is specified for operation when the EDG is not synchronized to the grid to ensure the voltage regulator will protect driven equipment from over-voltages during accident conditions. Procedural controls will ensure that equipment voltages are maintained within acceptable limits during testing when paralleled to the grid.

The wider band for frequency is appropriate for testing done with the governor in the droop mode. Likewise the wider band for voltage is appropriate when paralleled to the grid.

All voltages and frequencies specified in SR 4.8.1.1.2 are representative of the analytical values and do not account for postulated instrument inaccuracy. Instrument inaccuracies for EDG voltage and frequency are administratively controlled.

Preventive maintenance includes those activities (including pro-test inspections, measurements, adjustments and preparations) performed to maintain an otherwise OPERABLE EDG in an OPERABLE status. Corrective maintenance includes those activities required to correct a condition that would cause the EDG to be inoperable.

Surveillance requirement 4.8.1.2 is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of the surveillance requirement, and to preclude de-energizing a required ESF bus or disconnecting a required offsite circuit during performance of surveillance requirements. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these surveillance requirements must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE. During Startup, prior to entering Mode 4, the surveillance requirements are required to be completed if the surveillance frequency has been exceeded or will be exceeded prior to the next scheduled shutdown.

3/4.8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Containment electrical penetrations and penetration conductors are protected by either deenergizing circuits not required during reactor operation or by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers during periodic surveillance.

The surveillance frequency applicable to molded case circuit breakers and lower voltage circuit breakers provides assurance of breaker reliability by testing at least one representative sample of each manufacturer's brand of molded case and lower voltage circuit breakers. Each manufacturer's molded case circuit breakers and lower voltage circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of molded case or lower voltage circuit breakers, it is necessary to further divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

Containment penetration conductor overcurrent protective device information is provided in the UFSAR.

3/4.9.1 BORON CONCENTRATION

The limit on the boron concentration of the Reactor Coolant System (RCS), the refueling cavity, the fuel storage pool and the refueling canal during refueling ensures that the reactor remains subcritical during Mode 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the Core Operating Limits Report (COLR). Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of Keff $\leq$ 0.95 during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

General Design Criterion 26 of 10CFR 50, Appendix A requires that two independent reactivity control systems of different design principles be provided. One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps. The fuel storage pool is also adjusted to the refueling boron concentration specified in the COLR.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see TS 3/4.9.8, "Residual Heat Removal (RHR) and Coolant Circulation - All Water levels, " and "Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance. The required boron concentration and the plant refueling procedures that verify the correct fuel-loading plan (including full core mapping) ensure that the Keff of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling. During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result the soluble boron concentration is relatively the same in each of these volumes.

The RCS boron concentration satisfies Criterion 2 10CFR50.36(c)(2)(ii).

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, the fuel storage pool and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core Keff ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a Keff $\leq$ 0.95. A note to this LCO modifies the Applicability. The note states that the limits on boron concentration are only applicable to the refueling canal, the fuel storage pool and the refueling cavity when those volumes are connected to the Reactor Coolant System. When the refueling canal, the fuel storage pool and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists. Above MODE 6, LCOs 3.1.1.1 and 3.1.1.2 ensure that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, the fuel storage pool or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately. Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g. temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately. In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions. Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

The Surveillance Requirement (SR) ensures that the coolant boron concentration in the RCS, and connected portions of the refueling canal, the fuel storage pool and the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to reconnecting portions of the refueling canal, the fuel storage pool or the refueling cavity to the RCS, this SR must be met per SR 4.0.4. If any dilution activity has occurred while the cavity or canal was disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS. A minimum frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The frequency is based on operating experience, which has shown 72 hours to be adequate.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of the source range neutron flux monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 DECAY TIME

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor pressure vessel ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. The 100-hour decay time is consistent with the assumptions used in the fuel handling accident analyses and the resulting dose calculations using the Alternative Source Term described in Reg. Guide 1.183.

The minimum requirement for reactor subcriticality also ensures that the decay time is consistent with that assumed in the Spent Fuel Pool cooling analysis. Delaware River water average temperature between October 15th and May 15th is determined from historical data taken over 30 years. The use of 30 years of data to select maximum temperature is consistent with Reg. Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants".

A core offload has the potential to occur during both applicability time frames. In order not to exceed the analyzed Spent Fuel Pool cooling capability to maintain the water temperature below 180°F, two decay time limits are provided. In addition, PSEG has developed and implemented a Spent Fuel Pool Integrated Decay Heat Management Program as part of the Salem Outage Risk Assessment. This program requires a pre-outage assessment of the Spent Fuel Pool heat loads and heatup rates to assure available Spent Fuel Pool cooling capability prior to offloading fuel.

3/4.9.4 CONTAINMENT BUILDING PENETRATIONS

During movement of irradiated fuel assemblies within containment the requirements for containment building penetration closure capability and OPERABILITY ensure that a release of fission product radioactivity within containment will not exceed the guidelines and dose calculations described in Reg Guide 1.183, Alternative Radiological Source Term for Evaluating Design Basis Accidents at Nuclear Power Plants. In MODE 6, the potential for containment pressurization as a result of an accident is not likely. Therefore, the requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements during movement of irradiated fuel assemblies within containment are referred to as "containment closure" rather than containment OPERABILITY. For the containment to be OPERABLE, CONTAINMENT INTEGRITY must be maintained. Containment closure means that all potential release paths are closed or capable of being closed. Closure restrictions include the administrative controls to allow the opening of both airlock doors and the equipment hatch during fuel movement provided that: 1) the equipment inside door or an equivalent closure device installed is capable of being closed with four bolts within 1 hour by a designated personnel; 2) the airlock doors are capable of being closed within 1 hour by designated personnel, 3) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 4) the plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange.

Administrative requirements are established for the responsibilities and appropriate actions of the designated personnel in the event of a Fuel Handling Accident inside containment. These requirements include the responsibility to be able to communicate with the control room, to ensure that the equipment hatch is capable of being closed, and to close the equipment hatch and personnel airlocks within 1 hour in the event of a fuel handling accident inside containment. These administrative controls ensure containment closure will be established in accordance with and not to exceed the dose calculations performed using guidelines of Regulatory Guide 1.183.

The containment serves to limit the fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10CFR100 and Reg Guide 1.183, Alternative Source Term, as applicable. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The Containment Equipment Hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into or out of containment. During movement of irradiated fuel assemblies within containment can be open provided that: 1) it is capable of being closed with four bolts within 1 hour by designated personnel, 2) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 3) the plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange. Good engineering practice dictates that the bolts required by the LCO are approximately equally spaced.

An equivalent closure device may be installed as an alternative to installing the Containment Equipment Hatch inside door with a minimum of four bolts. Such a closure device may provide penetrations for temporary services used to support maintenance activities inside containment at times when containment closure is required; and may be installed in place of the Containment Equipment Hatch inside door or outside door. Penetrations incorporated into the design of an equivalent closure device will be considered a part of the containment boundary and as such will be subject to the requirements of Technical Specification 3/4.9.4. Any equivalent closure device used to satisfy the requirements of Technical Specification 3/4.9.4.a will be designed, fabricated, installed, tested, and utilized in accordance with established procedures to ensure that the design requirements for the mitigation of a fuel handling accident during refueling operations are met. In case that this equivalent closure device is installed in lieu of the equipment hatch inside door, the same restrictions and administrative controls apply to ensure closure will take place within 1 hour following a Fuel Handling Accident inside containment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during operation in MODES 1, 2, 3, and 4 as specified in LCO 3.6.1.3, "Containment Air Locks". Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown, when containment closure is not required and frequent containment entry is necessary, the air lock interlock mechanism may be disabled. This allows both doors of an airlock to remain open for extended periods. During movement of irradiated fuel assemblies within containment, containment closure may be required; therefore, the door interlock mechanism may remain disabled, and both doors of each containment airlock may be open if: 1) At least one door of each airlock is capable of being closed within 1 hour by dedicated personnel,) 2) either the Containment Purge System or the Auxiliary Building Ventilation System taking suction from the containment atmosphere are operating and 3) The plant is in Mode 6 with at least 23 feet of water above the reactor pressure vessel flange.

In the postulated FHA, the revised dose calculations performed using RG 1.183 criteria, do not assume automatic containment purge isolation thus allowing for continous monitoring of containment acitivity until the release pathways are isolated. If required, manual isolation of containment purge can be initiated from the control room.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods may include the use of a material that can provide a temporary atmospheric pressure, ventilation barrier. Any equivalent method used to satisfy the requirements of Technical Specification 3/4.9.4.c.1 will be designed, fabricated, installed, tested, and utilized in accordance with established procedures to ensure that the design requirements for the mitigation of a fuel handling accident during refueling operations are met.

The surveillance requirement 4.9.4.2 demonstrates that the necessary hardware, tools, and equipment are available to close the equipment hatch. The surveillance is performed once per refueling prior to the start of movement of irradiated fuel assemblies within the containment. This surveillance is only required to be met when the equipment hatch is open.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity conditions during CORE ALTERATIONS.

3/4.9.6 MANIPULATOR CRANE

The OPERABILITY requirements for the manipulator cranes ensure that: 1) manipulator cranes will be used for movement of control rods and fuel assemblies, 2) each crane has sufficient load capacity to lift a control rod or fuel assembly, and 3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE BUILDING

The restriction on movement of loads in excess of the nominal weight of a fuel and control rod assembly and associated handling tool over other fuel assemblies in the storage pool ensures that in the event this load is dropped (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the accident analyses.

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirements that at least one residual heat removal loop be in operation ensures that (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F as required during the REFUELING MODE, and (2) sufficient coolant circulation is maintained through the reactor core to minimize the effects of a boron dilution incident and prevent boron stratification. A minimum flow rate of 1000 gpm is required. Additional flow limitations are specified in plant procedures, with the design basis documented in the Salem UFSAR. These flow limitations address the concerns related to vortexing and air entrapment in the Residual Heat Removal system, and provide operational flexibility by adjusting the flow limitations based on time after shutdown. The requirement to have two RHR loops OPERABLE when there is less than 23 feet of water above the reactor vessel flange ensures that a single failure of the operating RHR loop will not result in a complete loss of residual heat removal capability.

For support systems: Service Water (SW) and Component Cooling (CC), component redundancy is necessary to ensure no single active component failure will cause the loss of Decay Heat Removal. One piping path of SW and CC is adequate when it supports both RHR loops. The support systems needed before entering into the desired configuration (e.g., one service water loop out for maintenance in Modes 5 and 6) are controlled by procedures, and include the following:

- A requirement that the two RHR, two CC and two SW pumps, powered from two different vital buses be kept operable
- A listing of the active (air/motor operated) valves in the affected flow path to be locked open or disable.

Note that four filled reactor coolant loops, with at least two steam generators with at least their secondary side water level greater than or equal to 5% (narrow range), may be substituted for one residual heat removal loop. This ensures that single failure does not cause a loss of decay heat removal.

With the reactor vessel head removed and 23 feet of water above the reactor pressure vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR loop, adequate time is provided to initiate emergency procedures to cool the core.

3/4.9.9 (Not Used)

3/4.9.10 and 3/4/9/11 WATER LEVEL - REACTOR VESSEL AND STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.12 FUEL HANDLING AREA VENTILATION SYSTEM

The operability of the Fuel Handling Area Ventilation System during movement of irradiated fuel ensures that a release of fission product radioactivity within the Fuel Handling Building will not exceed the guidelines and dose calculations described in Reg. Guide 1.183, Alternative Radiological Source Term for Evaluating Design Basis Accidents at Nuclear Power Reactors.

3/4.10.1 SHUTDOWN MARGIN

This special test exception provides that a minimum amount of control rod worth is immediately available for reactivity control when tests are performed for control rod worth measurement. This special test exception is required to permit the periodic verification of the actual versus predicted core reactivity condition occurring as a result of fuel burnup or fuel cycling operations.

3/4.10.2 GROUP HEIGHT, INSERTION, AND POWER DISTRIBUTION LIMITS

This special test exception permits individual control rods to be positioned outside of their normal group heights and insertion limits during the performance of such PHYSICS TESTS as those required to 1) measure control rod worth, and 2) determine the reactor stability index and damping factor under xenon oscillation conditions.

3/4.10.3 PHYSICS TESTS

This special test exception permits PHYSICS TESTS to be performed at less than or equal to 5% of RATED THERMAL POWER with the Reactor Coolant System T_{avg} slightly lower than normally allowed so that the fundamental nuclear characteristics of the reactor core and related instrumentation can be verified. In order for various characteristics to be accurately measured, it is, at times, necessary to operate outside the normal restrictions of these Technical Specifications. For instance, to measure the moderator temperature coefficient at BOL, it is necessary to position the various control rods at heights which may not be allowed by Specification 3.1.3.5 which may, in turn, cause the RCS T_{avg} to fall slightly below the minimum temperature of Specification 3.1.1.4.

3/4.10.4 NO FLOW TESTS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.11.1 LIQUID EFFLUENTS

3/4.11.1.1 Deleted

3/4.11.1.2 Deleted

3/4.11.1.3 Deleted

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 Deleted

3/4.11.2.2 Deleted

3/4.11.2.3 Deleted

3/4.11.2.4 Deleted

3/4.11.2.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the waste gas holdup system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of oxygen below the specified values provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

This specification is not applicable to portions of the Waste Gas System Removed from service for maintenance, provided that the portions removed for maintenance are isolated from sources of hydrogen and purged of hydrogen to less than 4% by volume.

3/4.11.3 Deleted

3/4.11.4 Deleted

3/4.12 Deleted

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5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be shown in Figure 5.1.1

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1-2.

UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC, shall be as shown in Figure 5.1-3.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The reactor containment building is a steel lined, reinforced concrete building of cylindrical shape, with a dome roof and having the following design features:

a. Nominal inside diameter = 140 feet.

b. Nominal inside height = 210 feet.

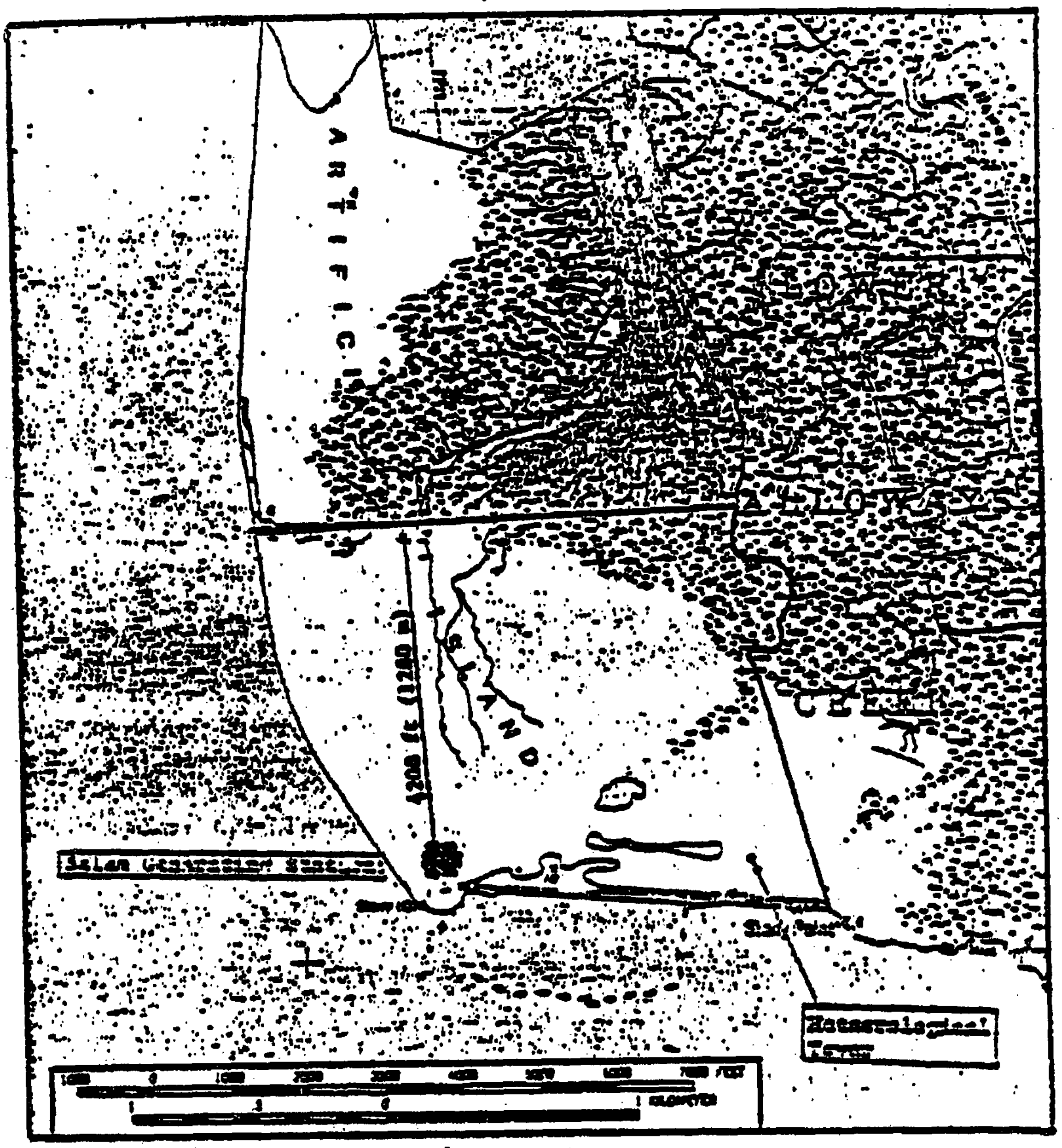
c. Minimum thickness of concrete walls = 4.5 feet.

d. Minimum thickness of concrete roof = 3.5 feet.

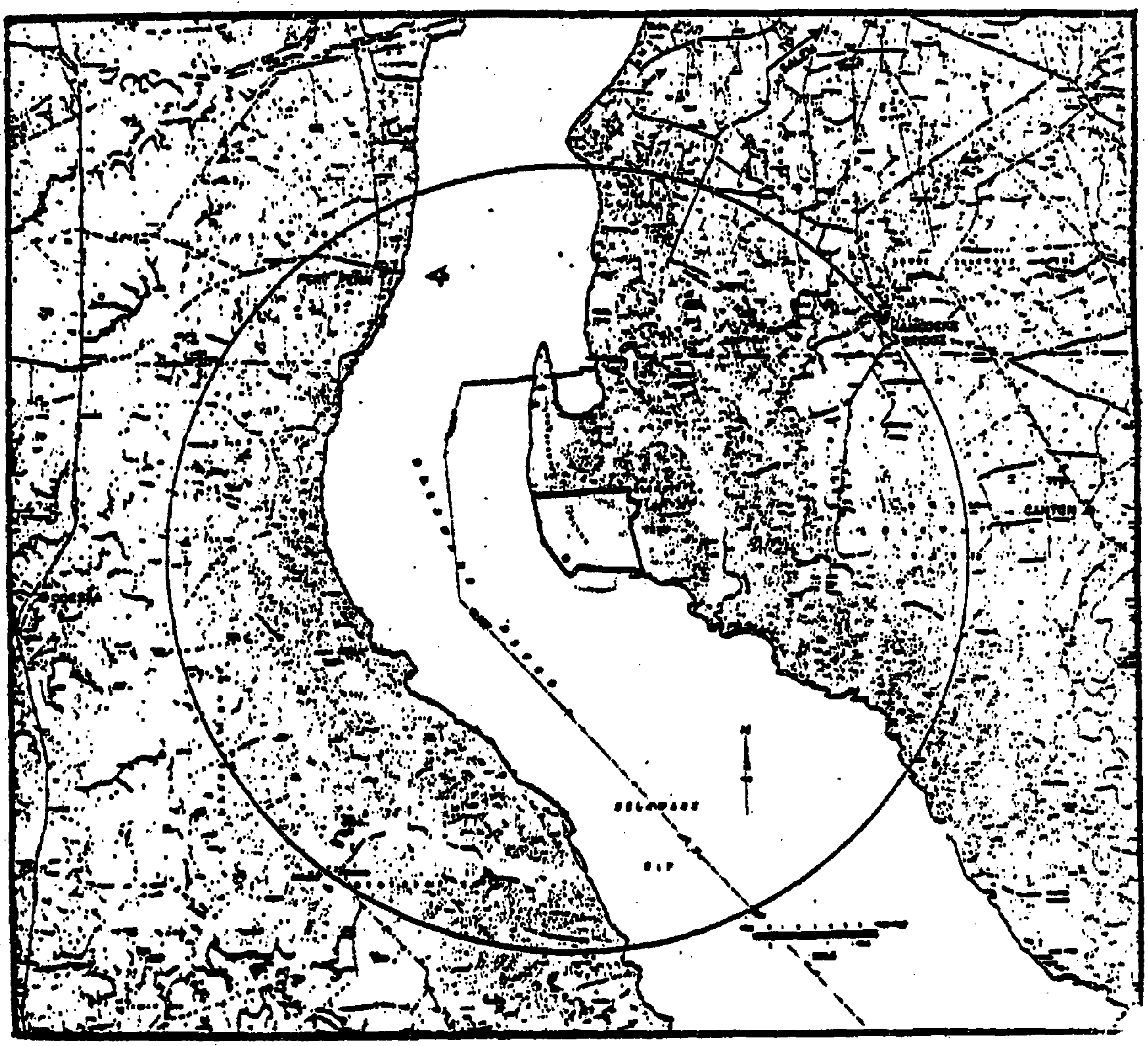
e. Minimum thickness of concrete floor mat = 16 feet.

f. Nominal thickness of steel liner = 1/4 to 1/2 inch.

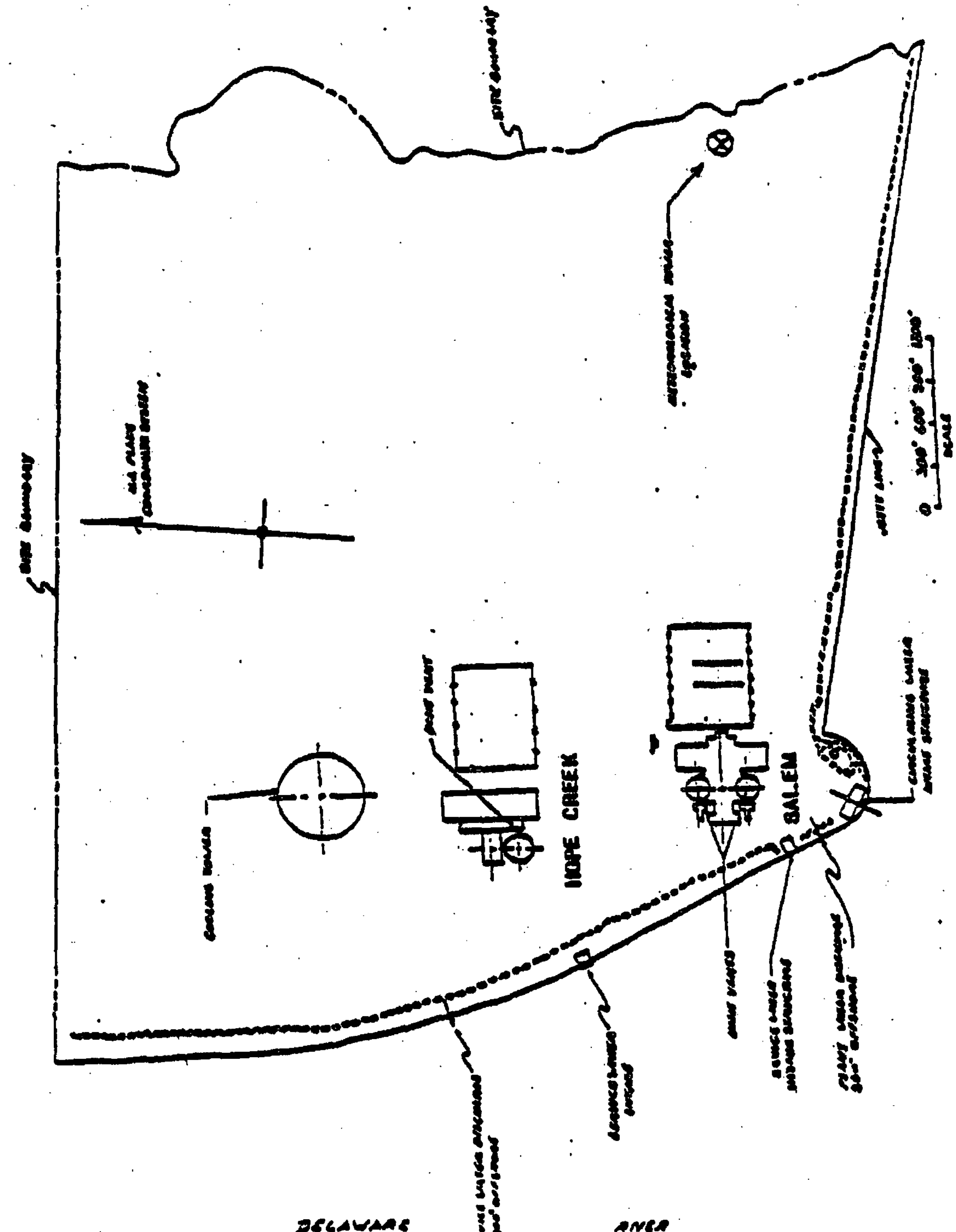
g. Net free volume = 2.62 x 10^6 cubic feet.



EXCLUSION AREA
FIGURE 5.1-1



LOW POPULATION ZONE
FIGURE 5.1-2



AREA PLOT PLAN OF S[illegible]

FIGURE 5.1-3

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The reactor containment is designed and shall be maintained for a maximum internal pressure of 47 psig. Containment air temperatures up to 351.3°F are acceptable providing the containment pressure is in accordance with that described in the UFSAR.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of zircaloy or ZIRLO clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with NRC-approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

CONTROL ROD ASSEMBLIES

5.3.2 The reactor core shall contain 53 full length and no part length control rod assemblies. The full length control rod assemblies shall contain a nominal 142 inches of absorber material. The nominal values of absorber material shall be 80 percent silver, 15 percent indium and 5 percent cadmium. All control rods shall be clad with stainless steel tubing.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirement specified in Section 4.1 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 680°F.

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1.1 The new fuel storage racks are designed and shall be maintained with:

a. A maximum K_{eff} equivalent of equal to 0.95 with the storage racks flooded with unborated water.

b. A nominal 21.0 inch center-to-center distance between fuel assemblies.

c. Unirradiated fuel assemblies with enrichments less than or equal to 4.25 weight percent (w/o) U-235 with no requirements for Integral Fuel Burnable Absorber (IFBA) pins.

d. Unirradiated fuel assemblies with enrichments (E) greater than 4.25 w/o U-235 and less than or equal to 5.0 w/o U-235 which contain a minimum number of Integral Fuel Burnable Absorber (IFBA) pins. This minimum number of IFBA pins shall have an equivalent reactivity hold-down which is greater than or equal to the reactivity hold down associated with N IFBA pins, at a nominal 2.35 mg B-10/linear inch loading (1.5X), determined by the equation below:

$$N = 42.67 (E - 4.25)$$

5.6.1.2 The spent fuel storage racks are designed and shall be maintained with:

a. A maximum Keff equivalent of 0.95 with the storage racks filled with unborated water.

b. A nominal 10.5 inch center-to-center distance between fuel assemblies stored in Region 1 (flux trap type) racks.

c. A nominal 9.05 inch center-to-center distance between fuel assemblies stored in Region 2 (non-flux trap) racks.

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DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 124'8".

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1632 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.7.1 The components identified in Table 5.7-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7-1.

TABLE 5.7-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at $\leq$ 100°F/hr and 200 cooldown cycles at $\leq$ 100°F/hr (pressurizer cooldown at $\leq$ 200°F/hr).	Heatup cycle - T_{avg} from $\leq$ 200°F to $\geq$ 542°F. Cooldown cycle - T_{avg} from $\geq$ 542°F to $\leq$ 200°F.
	80 loss of load cycles.	Without immediate turbine or reactor trip.
	40 cycles of loss of offsite A.C. electrical power.	Loss of offsite A.C. electrical power source supplying the onsite Class 1E distribution system.
	80 cycles of loss of flow in one reactor coolant loop.	Loss of only one reactor coolant pump.
	400 reactor trip cycles.	100% to 0% of RATED THERMAL POWER.
	200 large step decreases in load.	50% of RATED THERMAL POWER step load decrease with steam dump.

TABLE 5.7-1 (Continued)

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	1 main reactor coolant pipe break.	Break in a reactor coolant pipe > 13.5 inches equivalent diameter.
	Operating Basis Earthquake	50 cycles
	Design Basis Earthquake	10 cycles; 0.20g horizontal, 0.136g vertical.
	50 leak tests.	Pressurized to ≥ 2485 psig.
	5 hydrostatic pressure tests	Pressurized to ≥ 3107 psig.
Secondary System	1 steam line break	Break in a steam line > 6 inches equivalent diameter.
	5 hydrostatic pressure tests	Pressurized to ≥ 1356 psig.
	10 turbine roll tests	Turbine roll on pump heat resulting in plant cooldown > 100°F/hr.

6.1 RESPONSIBILITY

6.1.1 The plant manager shall be responsible for overall facility operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Senior Nuclear Shift Supervisor or, during his absence from the Control Room, a designated individual shall be responsible for the Control Room command function. A management directive to this effect, signed by the senior corporate nuclear officer, shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

6.2.1 ONSITE AND OFFSITE ORGANIZATIONS

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be established and defined from the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Salem Updated Final Safety Analysis Report and updated in accordance with 10 CFR 50.71(e).

b. The plant manager shall be responsible for overall facility safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plants.

c. The senior corporate nuclear officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plants to ensure nuclear safety.

d. The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

6.2.2 FACILITY STAFF

The Facility organization shall be subject to the following:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1.

FACILITY STAFF (Continued)

b. At least one licensed Reactor Operator shall be in the control room when fuel is in the reactor. In addition, at least one licensed Senior Reactor Operator shall be in the Control Room area at all times.

c. All CORE ALTERATIONS shall be observed and directly supervised by a licensed Senior Reactor Operator who has no other concurrent responsibilities during this operation.

d. Administrative controls shall be developed and implemented to limit the working hours of personnel who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel, et al.). The controls shall include guidelines on working hours that ensure that adequate shift coverage is maintained without heavy use of overtime for individuals.

Any deviation from the working hour guidelines shall be authorized in advance by the plant manager or his designee, in accordance with approved administrative procedures and with documentation of the basis for granting the deviation.

Controls shall be included in the procedure such that overtime shall be reviewed monthly by the plant manager or his designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines shall not be authorized.

Figure 6.2-1 CORPORATE HEADQUARTERS AND OFF-SITE ORGANIZATION FOR MANAGEMENT AND TECHNICAL SUPPORT

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FIGURE 6.2-2 FACILITY ORGANIZATION

(Deleted)

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION

SALEM UNIT 2

WITH UNIT 1 IN MODES 5 OR 6 OR DE-FUELED		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODES 1, 2, 3 & 4	MODES 5 & 6
SNSS	1[a]	1[a]
SRO	1[b]	none
STA	1[b]	none
NCO	2	1
EO/UO	3	2[c]
Maintenance Electrician	1	none
Rad. Pro. Technician	1[a]	1[a,e]

WITH UNIT 1 IN MODES 1, 2, 3 OR 4		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODES 1, 2, 3 & 4	MODES 5 & 6
SNSS	1[a]	1[a]
SRO	1[b]	none
STA	1[b]	none
NCO	2	1
EO/UO	3[d]	1
Maintenance Electrician	1[a]	none
Rad. Pro. Technician	1[a]	1[a]

a/ Individual may fill the same position on Unit 1.

b/ Individual who fulfills the STA requirement may fill the same position on Unit 1. The STA, if a licensed SRO, may concurrently fill the SRO position on one unit; the other unit also requires a qualified SRO on shift.

c/ One of the two required individuals may fill the position on Unit 1, such that there are a total of three EO/UO's for both units.

d/ One of the three required individuals may fill the same position of Unit 1, such that there are a total of five EO/UO's for both units.

e/ Not needed if both reactors are de-fueled.

TABLE 6.2-1 (Continued)

SNSS	-	Senior Nuclear Shift Supervisor with a Senior Reactor Operator License on both units.
SRO	-	Individual with a Senior Reactor Operator License on both units (normally, a Nuclear Shift Supervisor).
NCO	-	Nuclear Control Operator with a Reactor Operator License on both units.
STA	-	Shift Technical Advisor (if licensed as SRO, may be assigned duties as a Nuclear Shift Supervisor).
EO/UO	-	Equipment Operator or Utility Operator.

Except for the Senior Nuclear Shift Supervisor, the Shift Crew Composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate the unexpected absence of on-duty shift crew members provided that immediate action is taken to restore the Shift Crew Composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewperson's being late or absent.

During any absence of the Senior Nuclear Shift Supervisor from the Control Room area while the unit is in any MODE, an individual with a valid SRO License shall be designated to assume the Control Room command function.

6.2.3 SHIFT TECHNICAL ADVISOR

6.2.3.1 The Shift Technical Advisor shall serve in an advisory capacity to the Senior Nuclear Shift Supervisor on matters pertaining to the engineering aspects assuring safe operation of the unit.

6.2.3.2 The Shift Technical Advisor shall have a Bachelor's Degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant for transients and accidents.

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the individual designated as the Radiation Protection Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, the individual designated as the Operations Manager who shall meet or exceed the minimum qualifcations of ANSI N18.1-1971 except as modified by Specification 6.3.3, and the licensed operators who shall comply with the requirements of 10CFR55.

6.3.2 The Operations Manager or Assistant Operations Manager shall hold an SRO license. The Senior Nuclear Shift Supervisors and Nuclear Shift Supervisors shall each hold a senior reactor operator license. The Nuclear Control Operators shall hold reactor operator licenses.

6.3.3 The Operations Manager shall meet one of the following:

1) Hold an SRO license, or

2) Have held an SRO license for a similar unit (PWR), or

3) Have been certified at an appropriate simulator for equivalent senior operator knowledge.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the facility staff shall:

1) be coordinated by each functional level manager (Department Head) at the facility and maintained under the direction of the Director - Nuclear Training

2) meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 for all affected positions except licensed operators and

3) comply with the requirements of 10CFR55 for licensed operators.

6.5 <u>REVIEW AND AUDIT</u> (THIS SECTION DELETED)

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6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Section 50.73 to 10CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the Station Operations Reivew Committee (SORC) and the resultant Licensee Event Report submitted to the Nuclear Review Board and the senior corporate nuclear officer.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The unit shall be placed in at least HOT STANDBY within one hour.

b. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within one hour. The senior corporate nuclear officer and senior management position with responsibility for independent nuclear safety assessment activities and quality program oversight shall be notified within 24 hours.

c. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the SORC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence.

d. The Safety Limit Violation Report shall be submitted to the Commission, the senior management position with responsibility for independent nuclear safety assessment activities and quality program oversight and the senior corporate nuclear officer within 14 days of the violation.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

g. PROCESS CONTROL PROGRAM implementation.

h. OFFSITE DOSE CALCULATION MANUAL implementation.

i. Quality Assurance Program for effluent and environmental monitoring.

6.8.2 Each procedure and administrative policy of 6.8.1 above, except 6.8.1.d and 6.8.1.e, and changes thereto, shall be reviewed and approved in accordance with requirements in Updated Final Safety Analysis Report (UFSAR) section 17.2 for SORC or for Technical Review and Control, as appropriate, prior to implementation and reviewed periodically as set forth in administrative procedures. Procedures of 6.8.1.d and 6.8.1.e shall be reviewed and approved in accordance with the Facility's Security and Emergency Plans or requirements in Updated Final SAfety Analysis Report (UFSAR) section 17.2 for Technical Review and Control, as appropriate, prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 On-the-spot changes to procedures of 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered.

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License on the unit affected.

c. The change is documented and receives the same level of review and approval as the original procedure under within 14 days of implementation.

6.8.4 The following programs shall be maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include (recirculation spray, safety injection, chemical and volume control, gas stripper, recombiners, ...). The program shall include the following:

(i) Preventative maintenance and periodic visual inspection requirements, and

(ii) Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in areas under accident conditions. This program shall include the following:

(i) Training of personnel,

(ii) Procedures for monitoring, and

(iii) Provisions for maintenance of sampling and analyses equipment.

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

(i) Identification of a sampling schedule for the critical variables and the control points for these variables,

(ii) Identification of the procedures used to measure the values of the critical variables,

(iii) Identification of process sampling points, including monitoring at the discharge of the condensate pumps for evidence of condenser in-leakage.

(iv) Procedures for the recording and management of data,

(v) Procedures defining corrective actions for off-control-point chemistry conditions,

(vi) A procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

d. Backup Method for Determining Subcooling Margin

A program which will ensure the capability to accurately monitor the Reactor Coolant System Subcooling Margin. This program shall include the following:

(i) Training of personnel, and

(ii) Procedures for monitoring

e. Deleted

6.8.4.f. Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995, as modified by the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after March 24, 1992 shall be performed no later than March 24, 2007.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 47.0 psig.

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.6 L_a for Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:
1) Overall air lock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a,

2) Seal leakage rate less than or equal to 0.01 L_a per hour when the gap between the door seals is pressurized to 10.0 psig.

Test frequencies and applicable extensions will be controlled by the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 will be applied to the Primary Containment Leakage Rate Testing Program.

6.8.4.g Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to the MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 CFR 20, Appendix B, Table II, Column 2,

3) Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.106 and with the methodology and parameters in the ODCM,

4) Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5) Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days.

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 92-day period would exceed a suitable fraction of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the SITE BOUNDARY conforming to the doses associated with 10 CFR Part 20, Appendix B, Table II, Column 1,

8) Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

6.8.4.h Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of the census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

6.8.4.i Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gallon per minute per SG.

3. The operational leakage performance criterion is specified in LCO 3.4.7.2, "Reactor Coolant System Operational Leakage."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria may be applied as an alternative to the 40% depth based criteria:

1. WEXTEX expanded region inspection methodology (W* Methodology). This alternate repair criteria is only applicable to Westinghouse Model 51 SGs with mill annealed Alloy 600 tubing expanded into the tubesheet using the Westinghouse explosive tube expansion (WEXTEX) process. The definitions that apply to W* are provided below:

   Bottom of WEXTEX transition (BWT) is the highest point of contact between the tube and the tubesheet at, or below the top-of-tubesheet, as determined by eddy current testing.

   W* Length is defined as the length of tubing below the bottom of the WEXTEX transition (BWT) that must be demonstrated to be non-degraded in order for the tube to maintain structural and leakage integrity. For the hot leg, the W* length is 7.0 inches, which represents the most conservative hot leg length.

   W* Distance is defined as the non-degraded distance from the top of the tubesheet to the bottom of the W* length, including the distance from the top-of-tubesheet to the bottom of the WEXTEX transition (BWT) and Non-Destructive Examination (NDE) measurement uncertainties (i.e., W* distance = W* length + distance to BWT + NDE uncertainties). The W* Distance is the larger of the following two distances as measured from the top-of-the-tubesheet (TTS): (a) 8-inches below the TTS or (b) the non-degraded distance from the TTS to the bottom of the W* length, including the distance from the TTS to the bottom of the WEXTEX transition (BWT) and Non-Destructive Examination (NDE) measurement uncertainties (i.e., W* distance = W* length + distance to BWT + NDE uncertainties)

   Tubes within the hot-leg region of the tubesheet with flaws identified in the W* Distance, shall be removed from service on detection by tube plugging. Flaws located below the W* distance within the hot-leg region of the tubesheet may remain in service regardless of size.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The portion of the tube within the hot-leg tubesheet region below the W* distance is excluded. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, d.3, and d.4 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

Note: Step 2 has two separate requirements (a and b), depending on the type of SG tubes installed.

2a. SGs with Alloy 600 Mill Annealed tubes: Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

2b SGs with Alloy 690 Thermally Treated tubes: Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

4. When the W* methodology has been implemented, inspect 100 percent of the inservice tubes for the entire hot-leg tubesheet W* distance with the objective of detecting flaws that may satisfy the applicable tube repair criteria of TS 6.8.4.i.c.1 every 24 effective full power months or one refueling outage (whichever is less).

e. Provisions for monitoring operational primary-to-secondary leakage.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, with a copy to the USNRC Administrator, Region I, unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant.

6.9.1.2 The startup report shall address each of the tests identified in the FSAR and shall include a description of measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year.

* A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

6.9.1.5 Reports required on an annual basis shall include:

a. DELETED

b. DELETED

c. The results of any specific activity analyses in which the primary coolant exceeded the limits of Specification 3.4.8. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while the limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

MONTHLY OPERATING REPORT

6.9.1.6 DELETED

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.7 The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The report shall include summaries, interpretations, and analysis of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR 50.

ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.8 The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous 12 months of operation shall be submitted before May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objective outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR 50.

* A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

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6.9.1.9 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Moderator Temperature Coefficient Beginning of Life (BOL) and End of Life (EOL) limits and 300 ppm surveillance limit for Specification 3/4.1.1.4,

2. Control Bank Insertion Limits for Specification 3/4.1.3.5,

3. Axial Flux Difference Limits and target band for Specification 3/4.2.1,

4. Heat Flux Hot Channel Factor, F_Q, its variation with core height, K(z), and Power Factor Multiplier PF_{xy}, Specification 3/4.2.2, and

5. Nuclear Enthalpy Hot Channel Factor, and Power Factor Multiplier, $PF_{\Delta H}$ for Specification 3/4.2.3.

6. Refueling boron concentration per Specification 3.9.1

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, July 1985 (W Proprietary), Methodology for Specifications listed in 6.9.1.9.a. Approved by Safety Evaluation dated May 28, 1985.

2. WCAP-8385, Power Distribution Control and Load Following Procedures - Topical Report, September 1974 (W Proprietary) Methodology for Specification 3/4.2.1 Axial Flux Difference Approved by Safety Evaluation dated January 31, 1978.

3. WCAP-10054-P-A, Rev. 1, Westinghouse Small Break ECCS Evaluation Model Using NOTRUMP Code, August 1985 (W Proprietary), Methodology for Specification 3/4.2.2 Heat Flux Hot Channel Factor. Approved for Salem by NRC letter dated August 25, 1993.

4. WCAP-10266-P-A, Rev. 2, The 1981 Version of Westinghouse Evaluation Model Using BASH Code, Rev. 2. March 1987 (W Proprietary) Methodology for Specification 3/4.2.2 Heat Flux Hot Channel Factor. Approved by Safety Evaluation dated November 13, 1986.

5. WCAP-12472-P-A, BEACON - Core Monitoring and Operations Support System, Revision 0, (W Proprietary). Approved February 1994.

6. CENPD-397-P-A, Rev. 1, Improved Flow Measurement Accuracy Using Crossflow Ultrasonic Flow Measurement Technology, May 2000

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any mid-cycle revisions or supplements shall be provided upon issuance for each reload cycle to the NRC.

6.9.1.10 STEAM GENERATOR TUBE INSPECTION REPORT

A report shall be submitted within 180 days after the initial entry into HOT SHUTDOWN following completion of an inspection performed in accordance with the Specification 6.8.4.i, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing.

h. Information regarding the application of W* inspection methodology (applicable to tubes within the hot-leg region of the tubesheet); including the number of indications, the location of indications (relative to the BWT and TTS), the orientation (axial, circumferential, volumetric), the severity of each indication (e.g., near through-wall or not through wall), the tube side where the indication initiated (inside or outside diameter), the cumulative number of indications detected in the tubesheet region as a function of elevation within the tubesheet, the condition monitoring and operational assessment main steam line leak rate (including aggregate calculated main steam line break leak rate from all other sources), and an assessment of whether the results were consistent with expectations regarding the number of flaws and flaw severity (and if not consistent, a description of the proposed corrective action).

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, with a copy to the Administrator, USNRC Region I within the time period specified for each report.

6.9.3 Violations of the requirements of the fire protection program described in the Updated Final Safety Analysis Report which would have adversely affected the ability to achieve and maintain safe shutdown in the event of a fire shall be submitted to the U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator of the Regional Office of the NRC via the Licensee Event Report System within 30 days.

6.9.4 When a report is required by ACTION 8 OR 9 of Table 3.3-11 "Accident Monitoring Instrumentation", a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring for inadequate core cooling, the cause of the inoperability, and the plans and schedule for restoring the instrument channels to OPERABLE status.

6.10 RECORD RETENTION

In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All REPOF:ABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. DELETED

f. Records of changes made to Operating Procedures required by Specification 6.8.1.

g. Records of radioactive shipments.

h. Records of sealed source and fission detector leak tests and results.

i. Records of annual physical inventory of all sealed source material of record.

j. Records of reviews performed for changes made to procedures or reviews of tests and experiments, pursuant to 10CFR50.59.

6.10.2 The following records shall be retained for the duration of the Unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report, pursuant to 10CFR50.59.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of radiation exposure for all individuals entering radiation control areas.

d. Records of gaseous and liquid radioactive material released to the environs.

e. Records of transient or operational cycles for those facility components identified in Table 5.7-1.

f. Records of reactor tests and experiments.

g. Records of training and qualification for current members of the plant staff.

h. Records of in-service inspections performed pursuant to these Technical Specifications.

i. Records of Quality Assurance activities required by the QA Manual.

j. DELETED

k. Records of SORC meetings and activities of the Nuclear Review Board (and activities of its predecessor, the Offsite Safety Review (OSR) staff).

l. Records for Environmental Qualification which are covered under the provisions of Paragraph 2.C(7) and 2.C(8) of Facility Operating License DPR-75.

m. Records of the service lives of all hydraulic and mechanical snubbers including the date at which the service life commences and associated installation and maintenance records.

n. Records of secondary water sampling and water quality.

o. Records of analyses required by the radiological environmental monitoring program which would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed.

p. Records of reviews performed for changes made to the OFFSITE DOSE CALCULATION MANUAL and the PROCESS CONTROL PROGRAM.

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

6.12.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

6.12.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

   (i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

   (ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Changes to the PCP:

1. Shall be documented and records of review performed shall be retained as required by Specification 6.10.3p. This documentation shall contain:

   a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   b) A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall become effective after review and acceptance by the SORC and the approval of the Plant Manager.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

6.14.2 Changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained as required by Specification 6.10.3p. This documentation shall contain:

a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

b) A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.106, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

2. Shall become effective after review and acceptance by the SORC and the approval of the Plant Manager.

3. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g. month/year) the change was implemented.

6.15 MAJOR CHANGES TO RADIOACTIVE LIQUID, GASEOUS AND SOLID WASTE TREATMENT SYSTEMS

6.15.1 Licensee initiated major changes to the radioactive waste system (liquid, gaseous and solid):

1. Shall be reported to the Commission in the UFSAR for the period in which the evaluation was reviewed by (SORC). The discussion of each change shall contain:

a. A summary of the evaluation that led to the determination that the change could be made in accordance with 10CFR50.59;

b. Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

c. A detailed description of the equipment, components and processes involved and the interfaces with other plant systems;

d. An evaluation of the change, which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the license application and amendments thereto;

e. An evaluation of the change, which shows the expected maximum exposures to individual in the unrestricted area and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the changes are to be made;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the (SORC).

2. Shall become effective upon review and acceptance by the SORC.

6.16 TECHNICAL SPECIFICATION (TS) BASES CONTROL PROGRAM

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. PSEG may make changes to the Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the License, or

2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. Proposed changes to the Bases that require either condition of Specification 6.16.b above shall be reviewed and approved by the NRC prior to implementation.

d. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

e. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

APPENDIX B

TO

FACILITY OPERATING LICENSE NO. DPR-70
SALEM GENERATING STATION UNIT 1
DOCKET NO. 50-272

AND

FACILITY OPERATING LICENSE NO. DPR-75
SALEM GENERATING STATION UNIT 2
DOCKET NO. 50-311

PSEG NUCLEAR LLC

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

SALEM GENERATING STATION
UNIT NOS. 1 AND 2

ENVIRONMENTAL PROTECTION PLAN
(NONRADIOLOGICAL)

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1.0 Objectives of the Environmental Protection Plan

The Environmental Protection Plan (EPP) is to provide for protection of nonradiological environmental values during operation of the nuclear facility. The principal objectives of the EPP are as follows:

(1) Verify that the facility is operated in an environmentally acceptable manner, as established by the Final Environmental Statement - Operating Licensing Stage (FES-OL) and other NRC environmental impact assessments.

(2) Coordinate NRC requirements and maintain consistency with other Federal, State and local requirements for environmental protection.

(3) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects.

Environmental concerns identified in the FES-OL which relate to water quality matters are regulated by way of the licensee's NJPDES permit.

2.0 Environmental Protection Issues

In the FES, dated April 1973, the staff considered the environmental impacts associated with the operation of Salem Generating Station Unit Nos. 1 and 2. Certain environmental issues were identified which required study or license conditions to resolve and to assure adequate protection of the environment. The Appendix B Environmental Technical Specifications (ETS) issued with the operating license included discharge restrictions and monitoring programs related to aquatic and terrestrial resources.

1. Protection of the aquatic environment by limiting the thermal characteristics of the discharge.

2. Protection of the aquatic environment from biocide used in plant operations.

3. Protection of the aquatic environment from suspended solids and changes in pH in releases from the non-radioactive liquid waste disposal system.

4. Surveillance programs for dissolved gases, suspended solids, chemical releases, and the general aquatic ecological surveys to establish impact of plant operation on the biotic environment.

2.1 Aquatic Issues

Requirements for study of station intake and discharges effects were removed from the ETS by License Amendments 51 (Unit 1) and 18 Unit 2, dated March 14, 1983 and March 11, 1983, respectively. These issues now are addressed by the effluent limitations and monitoring requirements contained in the effective NJPDES Permit No. NJ0005622 issued by the State of New Jersey, and by the determination of the State of New Jersey on the Section 316(a) and (b) demonstration submitted by licensee. The NRC will rely on the State for regulation of matters involving water quality and aquatic biota.

2.2 Terrestrial Issues

Requirements for study of station effects on terrapins and raptors have been met.

3.0 Consistency Requirements

3.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such activities do not involve an unreviewed environmental question and do not involve a change in the EPP*. Changes in station design or operation performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by Section 3.3 are not subject to the requirements of this Section.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable nonradiological environmental effects are confined to the on-site areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activity and obtain prior NRC approval. When such activity involves a change in the EPP, such activity and change to the EPP may be implemented only in accordance with an appropriate license amendment as set forth in Section 5.3 of this EPP.

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* This provision does not relieve the licensee of the requirements of 10 CFR 50.59.

A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns: (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the FES-OL, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) as significant change in effluents or power level; or (3) a matter, not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have a significant adverse environmental impact.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include written evaluations which provide bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question or constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1.0. The licensee shall include as part of the Annual Environmental Operating Report (per Subsection 5.4.1) brief descriptions, analyses, interpretations, and evaluations of such changes, tests and experiments.

3.2 Reporting Related to the NJPDES Permit or the State Certification

Changes to, or renewals of, the NJPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change or renewal is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The licensee shall notify the NRC of changes to the effective NJPDES Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the NJPDES Permit at the same time the application is submitted to the permitting agency.

3.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, and local environmental regulations are not subject to the requirements of Section 3.1.

4.0 Environmental Conditions

4.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to plant operation shall be recorded and reported to the NRC within 24 hours followed by a written report per Subsection 5.4.2. The following are examples: excessive bird impaction events; onsite plant or animal disease outbreaks; mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973; fish kills or impingement events on the intake screens; increase in nuisance organisms or conditions; unanticipated or emergency discharge of waste water or chemical substances.

No routine monitoring programs are required to implement this condition.

4.2 Environmental Monitoring

4.2.1 Aquatic Monitoring

The certifications and permits required under the Clean Water Act provide mechanisms for protecting water quality and, indirectly, aquatic biota. The Nuclear Regulatory Commission (NRC) will rely on the decisions made by the State of New Jersey under the authority of the Clean Water Act and, in the case of sea turtles and shortnose sturgeon, decisions made by the National Marine Fisheries Service (NMFS) under the authority of the Endangered Species Act, for any requirements pertaining to aquatic monitoring.

In accordance with Section 7(a) of the Endangered Species Act, on May 14, 1993, the National Marine Fisheries Service issued a Section 7 Consultation Biological Opinion related to the operation of Salem Unit 1 and 2 Generating Stations. This Section 7 Consultation entitled, "Reinitiation of a consultation in accordance with Section 7(a) of the Endangered Species Act regarding continued operation of the Salem and Hope Creek Nuclear Generating Stations on the eastern shore of the Delaware River in New Jersey," concluded that "...continued operation is not likely to jeopardize the continued existence of listed species."

PSEG Nuclear LLC shall adhere to the specific requirements within the Incidental Take Statement, to the Biological Opinion. Changes to the incidental take statement must be proceeded by consultation between the NRC, as the authorizing agency, and NMFS.

The Conservation Recommendations, to the Biological Opinion suggests conservation recommendations for implementation by Salem Generating Station. The Station shall implement these recommendations to the satisfaction of the NRC and National Marine Fisheries Service.

4.2.2 Terrestrial Monitoring

Terrestrial monitoring is not required.

5.0 Administrative Procedures

5.1 Review

The licensee shall provide for review of compliance with the EPP. The review shall be conducted independently of the individual or groups responsible for performing the specific activity. A description of the organization structure utilized to achieve the independent review function and results of the review activities shall be maintained and made available for inspection.

5.2 Records Retention

Records and logs relative to the environmental aspects of station operation shall be made and retained in a manner convenient for review and inspection. These records and logs shall be made available to NRC on request.

Records of modifications to station structures, systems and components determined to potentially affect the continued protection of the environmental shall be retained for the life of the station. All other records, data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Requests for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revision to the EPP.

5.4 Plant Reporting Requirements

5.4.1 Routine Reports

An Annual Environmental Operating Report describing implementation of this EPP for the previous year shall be submitted to the NRC prior to May 1 of each year.

The report shall include summaries and analyses of the results of the environmental protection activities required by Subsection 4.2 (if any) of this EPP for the report period, including a comparison with related preoperational studies, operational controls (as appropriate), and previous nonradiological environmental monitoring reports, and an assessment of the observed impacts of the plant operation on the environment. If harmful effects or evidence of trends toward irreversible damage to the environment are observed, the licensee shall provide a detailed analysis of the data and a proposed course of mitigating action.

The Annual Environmental Operating Report shall also include:

(1) A list of EPP noncompliances and the corrective actions taken to remedy them.

(2) A list of all changes in station design or operation, tests, and experiments made in accordance with Subsection 3.1 which involved a potentially significant unreviewed environmental question.

(3) A list of nonroutine reports submitted in accordance with Subsection 5.4.2.

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing results shall be submitted as soon as possible in a supplementary report.

5.4.2 Nonroutine Reports

A written report shall be submitted to the NRC within 30 days of occurrence of a nonroutine event. The report shall: (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact, and plant operating characteristics; (b) describe the probable cause of the event; (c) indicate the action taken to correct the reported event; (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such report at the same time it is submitted to the other agency.

APPENDIX C
ADDITIONAL CONDITIONS
OPERATING LICENSE NO. DPR-75

PSEG Nuclear LLC, and the Exelon Generation Company LLC shall comply with the following conditions on the schedules noted below:

Amendment Number	**Additional Condition**	**Implementation Date**
175	The licensee is authorized to relocate certain Technical Specification requirements to licensee-controlled documents. Implementation of this amendment shall include the relocation of these technical specification requirements to the appropriate documents, as described in the licensee's application dated January 11, 1996, as supplemented by letters dated February 26, May 22, June 27, July 12, December 23, 1996, and March 17, 1997, and evaluated in the staff's safety evaluation attached to this amendment.	The amendment shall be implemented within 60 days from March 21, 1997.
177	The licensee is authorized to upgrade the initiation circuitry for the power operated relief valves, as described in the licensee's application dated January 31, 1997, as supplemented by letters dated March 14, April 8, and April 28, 1997, and evaluated in the staff's safety evaluation attached to this amendment.	The amendment shall be implemented prior to entry into Mode 3 from the current outage for Salem Unit 2.
179	Containment Fan Cooler Units The licensee shall complete all modifications associated with the amendment request concerning Containment Fan Cooler Units (CFCU) response time dated October 25, 1996, as described in the letters supplementing the amendment request dated December 11, 1996, January 28, March 27, April 24, June 3, and June 12, 1997, prior to entry into Mode 3 following refueling outage 12. All modifications made in support of this amendment request and described in the referenced sumittals shall be in conformance with the existing design basis for Salem Unit 1, and programmatic controls for tank monitoring instrumentation shall be as described in the letter dated April 24, 1997. Post modification testing and confirmatory analyses shall be as described in the letter dated March 27, 1997. Future changes to the design described in these submittals may be made in accordance with the provisions of 10 CFR 50.59. Further, the administrative controls associated with CFCU operability and containment integrity described in the letters dated March 27, and April 24, 1997 shall not be relaxed or changed without prior staff review until such time as the license has been amended to include the administrative controls as technical specification requirements.	The amendment shall be implemented prior to entry into Mode 3 from the current outage for Salem Unit 2.
181	The licensee shall perform an evaluation of the containment liner anchorage by November 30, 1997, for the loading induced on the containment liner during a Main Steam Line Break event to confirm the assumptions provided in the Preliminary Safety Analysis Report and Updated Final Safety Analysis Report.	The amendment shall be implemented within 30 days from July 17, 1997.