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PSEG
Nuclear LLC

10 CFR 50.71(e)
10 CFR 50.54(a)(3)
10 CFR 54.37(b)
10 CFR 71.106(b)
TS 6.17.d (Unit 1)
TS 6.16.d (Unit 2)
NEI 99-04

LR-N19-0102

December 05, 2019

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

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

Hope Creek Generating Station
Renewed Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: **Submittal of Salem Generating Station Updated Final Safety Analysis Report, Revision 31, Salem Units 1 & 2 Technical Specification Bases changes, 10 CFR 54.37(b) review results for Salem Units 1 & 2, 2018 Summary of Revised Regulatory Commitments for Salem and PSEG Nuclear LLC Quality Assurance Topical Report, NO-AA-10, Revision 88**

PSEG Nuclear LLC (PSEG) hereby submits:

- Revision No. 31 to the Salem Generating Station Units 1 and 2 Updated Final Safety Analysis Report (UFSAR) in accordance with the requirements of 10 CFR 50.71(e)(4) and 10 CFR 50.4(b)(6)

- Revision No. 88 to the PSEG Nuclear LLC Quality Assurance Topical Report (QATR), NO-AA-10, which documents a change to the Salem/Hope Creek

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10 CFR 50.71(e)
10 CFR 50.54(a)(3)
10 CFR 54.37(b)
10 CFR 71.106
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(SHC) Quality Assurance Program (QAP) in accordance with the requirements of 10 CFR 50.54(a)(3) and 10 CFR 71.106(b)

- Complete updated copies of the Salem Unit 1 and Unit 2 Technical Specification Bases, which include changes through December 05, 2019, 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)

- The results of a review performed as required by 10 CFR 54.37(b) to identify any newly-identified Structure, System or Component (SSC) that would be subjected to an aging management review or evaluation of time-limited aging analyses (TLAAs) in accordance with 10 CFR 54.21

- A summary of regulatory commitments that were changed and not reported by other means during the time period between January 1, 2018 and November 25, 2019.

Revision No. 31 to the Salem UFSAR is being submitted in its entirety electronically via CD-ROM and contains identified text, table and figure changes required to reflect the plant configuration as of June 18, 2019, six months prior to this submittal. In addition, there are general editorial changes. In accordance with 10 CFR 50.71(e)(2)(ii), a summary of changes made under the provisions of 10 CFR 50.59 but not previously submitted to the Commission is provided in Attachment 1. The previous revision to the Salem UFSAR was issued on May 11, 2018.

Based on NRC Regulatory Issue Summary (RIS) 2015-17, "Review and Submission of Updates to Final Safety Analysis Reports, Emergency Preparedness Documents, and Fire Protection Documents," PSEG has reviewed Revision 31 of the UFSAR for security-related information (SRI). Consequently, Revision 31 of the UFSAR is being provided in its entirety as two separate versions each on its own CD. One version, on CD-1, contains SRI and should be withheld from public disclosure under 10 CFR 2.390. The information that is SRI is designated by the statement "Security-Related Information - Withhold Under 10 CFR 2.390" at the top of the page. The second version, on CD-2, redacts the information that is SRI and designates it as "Security-Related Information - Withheld Under 10 CFR 2.390." The version on CD-2 is suitable for public disclosure.

In accordance with the Nuclear Energy Institute (NEI) process for managing Nuclear Regulatory Commission (NRC) commitments and associated NRC notifications, PSEG performed a review of regulatory commitments to determine if there were any Salem changed/closed commitments that were not reported by other means during

10 CFR 50.71(e)
10 CFR 50.54(a)(3)
10 CFR 54.37(b)
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the time interval from January 1, 2018 through November 25, 2019. The review concluded that there were no changed or closed commitments during that time period.

PSEG has developed Revision 88 of the SHC Quality Assurance Topical Report, which governs the QAP. This version of the SHC QATR, NO-AA-10, replaces the previous version submitted to you in PSEG letter LR-N18-0053 dated May 11, 2018.

The changes to the QATR are being made in accordance with the requirements of 10 CFR 50.54(a)(3) and 10 CFR 71.106(b). The changes involved no reduction in commitments and therefore did not require prior NRC approval. 10 CFR 50.54(a)(3) requires that changes that do not reduce the commitments be submitted in accordance with 10 CFR 50.71(e). Revision 88 is the current version of the QATR that is in use at PSEG, and became effective on June 28, 2019.

A summary of the changes made to the QATR in Revision 88 is provided in Enclosure 1 of this letter. Enclosure 2 of this letter provides a copy of Revision 88 of the QATR for information purposes.

Enclosure 3 contains complete updated copies of the Salem Unit 1 and Unit 2 Technical Specification Bases with changes through December 05, 2019.

An evaluation was completed to determine whether any newly-identified SSCs existed in support of submitting Salem UFSAR Revision 31. This evaluation involved reviewing pertinent documentation for the period subsequent to the last Salem UFSAR revision. The evaluation concluded that there were no newly-identified SSCs and no changes to the Salem current licensing basis that would have caused any newly-identified SSCs for which aging management reviews or time-limited aging analyses would apply.

As required by 10 CFR 50.71(e)(2)(i), I certify that to the best of my knowledge, the information contained in the CD Enclosures and Attachments to this letter, which pertain to the Salem UFSAR Revision 31, accurately reflect information and analyses submitted to the NRC, or prepared pursuant to NRC requirements as described above. There are no regulatory commitments contained in this letter.

10 CFR 50.71(e)
10 CFR 50.54(a)(3)
10 CFR 54.37(b)
10 CFR 71.106
TS 6.17.d (Unit 1)
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NEI 99-04

If you have any questions or require additional information, please do not hesitate to contact Mr. Lee Marabella, at (856) 339-1208.

Sincerely,

Paul R Duke

Paul Duke
Manager, Licensing
PSEG Nuclear, LLC

Attachments:

1. Summary Report of UFSAR Changes

CD Enclosures:

1. CD-1, Salem UFSAR Rev. 31 (Withhold from public disclosure)
2. CD-2, Salem UFSAR Rev. 31 (Redacted version suitable for public disclosure)

Other Enclosures:

1. Quality Assurance Topical Report, NO-AA-10, Revision 88 Summary of Changes
2. Quality Assurance Topical Report, NO-AA-10, Revision 88
3. Salem Nuclear Generating Station Unit 1 & Unit 2 Technical Specification Bases as of December 05, 2019

CC (Cover letter, Other Enclosures 1, 2 and Attachment 1 only)

Administrator - Region I - USNRC
Licensing Project Manager - Salem and Hope Creek - USNRC
USNRC Senior Resident Inspector – Salem
Chief, New Jersey Bureau of Nuclear Engineering

(Cover letter, Other Enclosures 1 and 2 only)

Director, Division of Spent Fuel Management, Office of Nuclear Material Safety and Safeguards - USNRC

(Cover letter, Other Enclosures 1 and 2 only)

USNRC Senior Resident Inspector - Hope Creek

(Cover letter only)

Site Compliance Commitment Coordinator
Corporate Commitment Coordinator

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(Cover letter only)

Site Compliance Commitment Coordinator
Corporate Commitment Coordinator

Attachment 1

Summary Report of

UFSAR Changes

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 17-013	9.2	9.2-9	Changes to the description of how the Service Water flow to the CCHX is controlled.	Change reviewed and approved by Design Engineering. A 10CFR50.59 screening and evaluation is included in the SCN 17-013 package.
SCN 18-002	11.4, 7.5	11.4-20, T11.4-3 sh2, T11.4-4 sh2, T7.5-4 sh2	Changes made to reflect removal of Radiation Monitors 1R47 and 2R47 from the electrical penetration area in the Auxiliary Building.	Design Change package 80120796 instituted. Associated 50.59 Screening included in SCN 18-002 package.
SCN 18-006	7.2, 7.7, 15TOC, 15.2	7.2-27, -28, -30, T7.2-2 sh3, 7.7-1, -2, -3, -5, F7.7-1, 15-xiv, 15.2-16, -49, F15.2-11 sh 1&2	Changes made to reflect the disabling of automatic rod withdrawal for rod control.	Design Change package 80122162 instituted. Associated 50.59 Screening is included in the SCN 18-006 package.
SCN 18-007	9.4	9.4-1b	Change reflects installation of non-safety related demineralizer skid and safety related piping from #22 chilled water pump discharge to the expansion tank.	Design Change package 80114076 (Unit 2) instituted. Associated 50.59 Screening is included in the SCN 18-007 package.
SCN 18-008	4 TOC, 4.1, 4.3, 15 TOC, 15.1, 15.3	4-iv, T4.1-2 sh1, 4.3-55 thru 4.3-63, 15-ii, 15.1-24, -25, -26, T15.1-2 sh 3 & 4, 15.3-15, -21	Change reflects the addition of a discussion of Doppler models, PARAGON and NEXUS. It also added new section in Chapter 4.3 for pin power reconstruction and it adds a new section in Chapter 15 for PARAGON and NEXUS.	Change reviewed and approved by Nuclear Fuels. A 10CFR50.59 screening and evaluation is included in the SCN 18-008 package.
SCN 18-010	3.6	3.6-55	Change reflects a correction to page missed by previously implemented SCN 15-016 and 18-003 for changing the CO2 system from automatic to manual in the diesel generator area.	Change reviewed and approved by Salem Plant Engineering. A Fire Protection Change Regulatory Review evaluation is included in the SCN 18-010 package.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 18-011	3.6	3.6-50	Changes reflect revision to the description of how a Moderate Energy Line Break postulated to occur in the Component Cooling Heat Exchanger rooms can affect the component cooling water pump motors.	Change reviewed and approved by Design Engineering. A 10CFR50.59 screening is included in the SCN 18-011 package.
SCN 18-012	15.2	15.2-57, -62	Change reflects a deletion of references voided in DCP 80118856 but not removed from the UFSAR by SCN 16-017 for DCP 80118856. Added correct reference to UFSAR for PORV analysis.	Change reviewed and approved by Design Engineering. A 10CFR50.59 screening is included in the SCN 18-012 package.
SCN 18-013	4.2	4.2-13	Change reflects a fuel design change. Reconstitutable Top Nozzle is replaced by Westinghouse Integral Nozzle design for RFA-2 fuel.	Design Change package 80120891 instituted. A 50.59 screening is included in the SCN 18-013 package.
SCN 18-015	5.2	5.2-69, -70	Change reflects a revision of the description of how intersystem leakage would be detected for the Safety Injection System.	Change reviewed and approved by Plant Engineering. A 50.59 Screening is included in SCN 18-015 package.
SCN 18-016	15.4	F15.4-48, -49	Change reflects the Salem 2 Cycle 24 Core Reload Design.	Design Change package 80120308 instituted. Associated 50.59 Screening included in SCN 18-016 package.
SCN 18-017	6.2, 7 TOC, 7.7, 9.4, 10.2, 11.3	6.2-79, -80, 7-vii, 7.7-12, -13, -21a, T7.7-3 sh1, T7.7-4 sh1, T7.7-5 sh1, T7.7-6 sh1, 9.4-15, -15a, -15b, 10.2-6a, -6b, -7, -8, 11.3-12, -13	Change reflects the relocation of requirements previously placed in the UFSAR to the TRM for various equipment.	Change reviewed and approved by Design Engineering, Plant Engineering and Radiation Protection. A 50.59 Screening is included in SCN 18-017 package.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 18-018	10.2	10.2-6b, -7	Change reflects an alternative to specific actions for the Turbine Overspeed Protection System provided the plant is not in an unanalyzed condition. The actions were relocated from Unit 1 and 2 Technical Specifications by amendments 224 and 205.	Change reviewed and approved by Plant Engineering. A 50.59 Screening is included in SCN 18-018 package.
SCN 18-019	5.5	5.5-7	Change reflects the replacement of the RCP Seal No. 1 with Sigma Seal. Seal replacement is being performed over multiple outages.	Design Change package 80122692 instituted. A 50.59 screening is included in the SCN 18-019 package.
SCN 18-021	15.4	15.4-35	The change revises the description of single-failure considerations within the analyses to eliminate reader confusion.	Change reviewed and approved by Nuclear Fuels and Reactor Engineering. A 50.59 Screening is included in the SCN 18-021 package.
SCN 19-003	Appendix 3A	3A-12, -14, -16	Change reflects a revision to the requirement of Ferrite content in austenetic weld filler materials and the adoption of Reg Guide 1.31 Revision 4.	Change reviewed and approved by Design Engineering. Associated 50.59 Screening included in SCN 19-003 package.
SCN 19-006	9.1	T9.1-4 Sheet 2	Changes reflect a correction to containment bulding equipment hatch weight.	Change reviewed and approved by Reactor Engineering. A 50.59 Screening is included in the SCN 19-006 package.
SCN 19-008	13 TOC, 13.1	13-i, -ii, -iii, 13.1-1 thru -12, T13.1-1 sh1, F13.1-1, -2, -3, -4	Change reflects removal of information concerning organization structure and reporting relationships. This information is duplicated in the QATR or is considered excessive detail that is not important to provide an understanding of the plant's design and operation.	Change reviewed and approved by Human Resources and Nuclear Oversight. A regulatory review form for a non-regulatory change is included in the SCN 19-008 package.

CN #	SECT	AFFECTED PAGES, TABLES & FIGURES	DESCRIPTION	BASIS
SCN 19-009	9.2	9.2-8	Change reflects a correction to clarify the SWIS sump pump capacity description.	Change reviewed and approved by Plant Engineering. A 50.59 Screening is included in the SCN 19-009 package.
SCN 19-011	9.1	T9.1-4 sheet 6	Change reflects a revision to the Service Water Pump weight.	Design Change package 80122526 instituted. Associated 50.59 Screening included in the SCN 19-011 package.
SCN 19-012	9.1	T9.1-4 sheets 4 & 5	Change reflects an update to the Heavy Load Weight and Maximum Safe Lift Height for Recipricating Charging pump coupling and crane capacity.	Change reviewed and approved by Reactor Engineering. A 50.59 Screening is included in the SCN 19-012 package.
SCN 19-013	Appendix B	B-32	Change reflects an update of the acceptance criteria for pH values for the SFP teltale and seismic gap.	Change reviewed and approved by Programs Engineering. A 50.59 Screening is included in the SCN 19-013 package.

For the worst case scenario, six sprinkler heads are assumed to supply approximately 393 gpm to suppress the fire. Flow restrictors (orifices) were added to the two drains in the room to prevent drain flow from exceeding the sump tank overflow line capacity, thus precluding flooding of other rooms on the 64 ft elevation due to backflow through the interconnected floor drains.

Area 3 - Electrical Penetration Area - Elevation 78 Feet

This area contains only the fire protection preaction sprinkler piping which is similar to that installed in the 64 ft switchgear room that replaced the CO2 fire suppression system.

In a fire, the pressurized air that is in the line between the deluge supply valve and the closed sprinkler heads is released by the melting of a fusible link that opens the deluge valve when other electric alarm signals have been received. When the deluge valve opens the dry preaction sprinkler piping is charged with water. The backpressure provided by the 20 psig air that is maintained in the dry preaction system piping helps prevent the occurrence of water hammer in the preaction system when the deluge valve opens. Under the assumed worst case conditions, the preaction system can supply approximately 382 gpm flowing to six sprinkler heads to suppress a fire. Because the existing 4-inch drain in the room is capped due to HELB considerations, a new 4-inch drain was added that empties to the RHR valve room on the 55 ft elevation. Check valves in the drain lines prevent backflow interaction with the two new drains added to 84 ft switchgear room that also empty to the RHR valve room. The drainage from the 84 ft switchgear room and the 78 ft elevation electrical penetration room combine and empty into the RHR valve room and from there drain to one RHR pump room on the 45 ft elevation.

Areas 4, 5, and 6 - Rod Control Reactor Trip Breakers and Miscellaneous 460 V Vital Electrical Gear - Elevation 84 Feet

Curbing at access points into these areas has been provided to prevent flooding from adjacent areas. The 460 V switchgear room on the 84 ft elevation also replaced the CO2 fire suppression system with an automatically initiated, interlocked, preaction sprinkler system that was designed and installed per the requirements in NFPA 13 (2002 Edition). The preaction sprinkler system in the 460 V switchgear room operated the same as those in the 4160 V Switchgear Room and in the Electrical Penetration Room.

The fire protection piping within the 460 V switchgear room meets Seismic Category I requirements. The fire protection tie-ins to the 6-inch fire protection header and isolation valves located outside the room in the hallway on the 84 ft elevation meet Seismic II/I requirements. There are two existing 4-inch floor drains in the hallway that drain to the waste holdup tanks on the 64 ft elevation. Two new 4-inch drains were added to remove water from the switchgear room should the sprinkler system discharge in the event of a fire. Assuming the worst-case scenario, six sprinkler heads in a tight area grouping would discharge 379 gpm in the event of a fire in the room. The drain lines, which are open-ended and equipped with check valves to prevent backup, empty to the RHR valve room on the 55 ft elevation. From there, the water drains via an existing floor drain to a RHR pump room sump pit on the 45 ft elevation. With flooding of one RHR pump room that could potentially incapacitate one RHR pump, the other RHR pump located in the adjacent, separate, non-flooded RHR pump room would be available. No other design basis accidents are postulated to occur coincidental with a fire. However, switchgear room fires may result in the loss of both onsite and offsite power to the vital buses, which could result in a total loss of the RHR system, making it temporarily unavailable for providing decay heat removal. Safe shutdown for Salem is defined as hot standby. Existing procedures identify repairs to the components that are required for establishing one RHR loop as necessary for achieving cold safe shutdown. In addition, Appendix R provides for remote cabling of either RHR pump in the event of a fire. However, the maximum flood level in the RHR pump room 30 minutes after actuation of one of the preaction sprinkler systems added to the switchgear rooms and the electrical penetration room is calculated to be less than 13 inches, which is well below the elevation of an RHR pump.

Area 7 - Safety Injection Pump Room - Elevation 84 Feet

This area contains MEL piping. Floor drainage capacity however is adequate to prevent flooding of the compartment. Water spray from service water or demineralized water piping could affect safety injection pump motors. The safety injection pump motors have been protected from overhead spray by means of a protective shroud.

Area 8 - Component Cooling Heating Exchanger Rooms -Elevation 84 Feet

This area contains service water and fire protection MEL piping. Floor drainage capacity in the area is adequate to prevent flooding. Water spray from service water pipe cracks could affect 22 or 23 component cooling pump motors and associated controls, dependent on the crack location.

In the unlikely event that one of the larger tanks without a dike or berm were to drain its contents, most likely due to operator error, the resulting flood would spread out over an extensive floor area in the Auxiliary Building which would limit the flood height and preclude damaging safe shutdown equipment.

The waste holdup, waste monitor-holdup, and evaporator bottoms storage tanks are diked to contain the volumes within the tank area.

The monitor tanks are not diked, but the failure of any of these tanks would not cause flooding serious enough to prevent Class I (seismic) safety-related equipment from operating satisfactorily. Aside from floor drainage systems, stairwells, and floor openings would prevent water from rising to levels that could be termed critical.

A similar investigation showed that equipment arrangement and floor drainage systems design are adequate to prevent flooding in the event of a non-Class I (seismic) pipe rupture serious enough to prevent safeguards systems from operating satisfactorily.

Fire Protection pipe systems have been demonstrated to be adequately supported to withstand seismic events without structural pipe failure.

Nitrogen and hydrogen storage cylinders are located in the Auxiliary Building. Ruptures will not jeopardize the required operation of a Class I (seismic) system, since the tanks, located at Elevation 122 feet in corridors to the north and south of the drumming and baling area, are isolated from Class I (seismic) equipment by virtue of their location, as well as by concrete walls.

Supplementing the Public Service Electric & Gas (PSE&G) letter of November 2, 1972 (response to Mr. R. C. DeYoung's letter of September 26, 1972), the failure of carbon dioxide fire protection equipment will not affect operation of safeguards systems. Manual systems are provided in the diesel-generator areas. Manual carbon dioxide fire protection equipment is provided in the control and relay room areas.

3.6.5.14 Electrical Cable Environmental Qualification

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

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

3.6.6 References for Section 3.6

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

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

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

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

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

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

7. EPRI TR-1006937 "Extension of the EPRI Risk Informed ISI Methodology to Break Exclusion Region Programs," April 4, 2002.

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

Regulatory Guide 1.27 - ULTIMATE HEAT SINK (Revision 2)

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

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

Salem Generating Station is committed to the requirements of NQA-1-1994 for Quality Assurance Program requirements.

Regulatory Guide 1.29 - SEISMIC DESIGN CLASSIFICATION, 8/73

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

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

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

Regulatory Guide 1.31 - CONTROL OF FERRITE CONTENT IN STAINLESS STEEL WELD METAL PRIOR TO REVISION 4

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

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

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

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

ferrite will be the lowest in a given weld because of different welder manipulations necessary to overcome effects of gravity.

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

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

The basis for classifying the low, medium, and high energy input ranges is not given in the Regulatory Guide. Using the Westinghouse conservative welding procedure parameters, the following energy inputs are being applied to produce high quality welds. They are:

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

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

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

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

Westinghouse has a large amount of evidence showing that the above energy input ranges produce fissure-free weldments in both shop and onsite welding.

Westinghouse does not require in-process delta ferrite determination. When the welding material is tested (in accordance with the requirements of ASME Section III, NB2430, and includes delta ferrite determinations), sound welds displaying more than one

percent average delta ferrite content by any agreed method of determination will be considered unquestionable. All other sound welds which display less than 1 percent average delta ferrite will be considered acceptable provided there is no evidence of malpractice or deviation from procedure parameters. If evidence of the latter prevails, sampling will be required to determine the acceptability of the welds. The sample size shall be 10 percent of the welds in the system or component. If any of these weld samples are defective, that is, fail to pass bend tests as described by ASME, Section IX, all remaining welds shall be sampled and all defective welds shall be removed and replaced.

Field welding of the nuclear steam supply system and other nuclear class components is performed using Public Service Electric and Gas (PSE&G) welding procedures. In some areas of austenitic stainless steel welding, these procedures call for use of the 16-8-2 electrode. This particular electrode composition was developed to provide fissure-free welds in austenitic systems without reliance on ferrite content, which is generally limited to 3 percent, and frequently the amount is less than 1 percent. Therefore, ferrite control and determination, which comprise the bulk of the Regulatory Guide, are not considered applicable to the 16-8-2 welding electrode.

The 16-8-2 welding electrode was initially developed for service temperatures where delta ferrite exhibits a tendency to transform into the sigma phase, and embrittling condition in austenitic stainless steel. Service temperatures at the Salem Station are too low to support a need for this type of protection, but PSE&G's long service history with this welding composition (since 1955) in steam piping systems has provided a level of confidence and expertise which overrides the consideration of alternate materials. Service and inspection records show that numerous welds have been performed satisfactorily in high pressure steam service temperatures up to 1100°F for operating times exceeding 150,000 hours in the PSE&G generating systems.

Regulatory Guide 1.31 - <u>CONTROL OF FERRITE CONTENT IN STAINLESS STEEL WELD METAL REVISION 4, OCTOBER 2013</u>

Salem Generating Station adheres to Revision 4 of Regulatory Guide 1.31. Per this revision of the regulatory guide, ferrite content in the weld metal as depicted by a ferrite number (FN) of weld metal used for welds in austenitic stainless steel core support structures, reactor internals, and class 1, 2 and 3 components should be between 5 and 20. The lower limit provides sufficient ferrite to avoid microfissuring in welds, whereas the upper limit provides a ferrite content adequate to offset dilution and reduce thermal aging effects.

PSE&G welding and inspection practices comply with the intent of the Regulatory Guide and Appendices A and B to 10CFR50 in the following manner:

1. Strict control is maintained over electrode chemistry and identification for procedure qualification, welder qualification, and production welding. This is accomplished through purchase specifications, certified mill test reports, segregation of untested lots from approved lots, locked storage of welding supplies on site, recorded allocation of electrodes to welders, and maintenance of lot identity from site receiving to completed weld joint.

2. The weld procedure qualification demonstrates the capability of producing welds free from unacceptable fissuring. This includes visual examination of procedure qualification bend bars and macrotech specimens with the unaided eye and under 10 power magnification.

3. Welder performance qualification bend bars, when made, are examined in the same manner to verify that the welder's technique maintains freedom from unacceptable fissures.

4. Welds for nuclear class systems are subjected to a liquid penetrant and radiographic examination where required. Heavy wall welds, such as in the reactor coolant piping, are subjected to in-process examinations by a liquid penetrant and radiography at one or more intermediate stages in the welding out of the groove.

5. Ferrite content for each lot of austenitic stainless steel electrode is qualified by magnegage measurements of a test weld pad. For nuclear plant welds, ferrite

outside the range of 5FN to 20FN for E-308, E-309, and E-316 is considered rejectable.

6. Production welding parameters are monitored on a spot-check basis by the field welding supervision and the Field Quality Control Group.

Regulatory Guide 1.32 - USE OF IEEE STANDARD 308-1971, "CRITERIA FOR CLASS 1E ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS"

The Salem Station design satisfies the requirements of IEEE Standard 308-1971, with the exception that Class 1 diesel fuel oil storage capacity provides less than seven days of diesel operation under worst case loading. See Section 9.5.4 for a description of how long term Emergency Diesel generator fuel oil storage requirements are met.

Regulatory Guide 1.33 - QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION), 2/78 (endorses N18.7-1976/ANS 3.2)

The Salem Generating Station is committed to the requirements of NQA-1-1994. See the Quality Assurance Topical Report, Appendix C, Section 1.3.2.3 for further discussion.

Regulatory Guide 1.34 - CONTROL OF ELECTROSLAG WELD PROPERTIES

Electroslag welding of Nuclear Classes 1 and 2 components is confined to the area of reactor coolant piping elbows. These are made from cast clamshells of ASTM A351 Gr. CF-8M joined together on longitudinal seams by the electroslag process. Welding of these components was performed under specified weld procedure control monitored by Westinghouse. PSE&G also established that the shop production welds were in conformance to the procedure qualification.

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TABLE 4.1-2

ANALYTIC TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Section Referenced
Mechanical Design of Core Internals			
Loads, Deflections, and Stress Analysis	Static and Dynamic Modeling	Blowdown code, FORCE, Finite element structural analysis code, and others	
Fuel Rod Design			
Fuel Performance Characteristics (temperature, internal pressure, clad stress, etc.)	Semi-empirical thermal model of fuel rod with consideration of fuel density changes, heat transfer, fission gas release, etc.	Westinghouse fuel rod design model	4.2.1.3.1 4.3.3.1 4.4.2.2 4.4.3.4.2
Nuclear Design			
1) Cross Sections and Group Constants	Microscopic data	Modified ENDF/B library	4.3.3.2
	Macroscopic constants for homogenized core regions	LEOPARD/CINDER type or PHOENIX-P	4.3.3.2
	Group constants for control rods with self-shielding	HAMMER-AIM or PHOENIX-P	4.3.3.2
		PARAGON or NEXUS	4.3.3.2
2) X-Y and X-Y-Z Power Distributions, Fuel Depletion, Critical Boron Concentrations, x-y and X-Y-Z Xenon Distributions, Reactivity Coefficients	2-Group Diffusion Theory	TURTLE (2-D) or ANC(2-D or 3-D)	4.3.3.3
3) Axial Power Distributions Control Rod Worths, and Axial Xenon Distribution	1-D, 2-Group Diffusion Theory	PANDA or APOLLO	4.3.3.3

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

The square adapter plate is provided with round and obround penetrations to permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves which are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is a sheet metal shroud which sets the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and are fastened in place by screws and clamps located at two diagonally opposite corners. The clamps are attached to the nozzle by a specific arrangement of tack welds or tack weld(s) in combination with a stainless steel clamp screw, depending on the manufacturing process in place at the time a given fuel region was built. The spring screws apply a load directly to the base of the hold-down springs. The clamps do not have any bearing surfaces that load the spring to the nozzle, but primarily provide a stationary location for attachment of lock wires that prevent rotation of the spring screws. On the other two corners, integral pads are positioned which contain alignment holes for locating the upper end of the fuel assembly.

Salem Units 1 and 2 later implemented the Westinghouse Integral Nozzle (WIN) design in RFA-2 fuel assemblies. The WIN design, while similar to the RTN, incorporates design and manufacturing improvements to eliminate the Inconel 718 spring screw for attachment of the holddown springs. In the WIN nozzle, the springs are assembled into the nozzle pad and pinned in place. The WIN design provides a wedged rather than a clamped (bolted) joint to transfer the fuel assembly holddown forces into the top nozzle structure.

A replacement reconstitutable top nozzle (RRTN) design may be used in a reload cycle to replace the original reconstitutable top nozzle (RTN) or the WIN on an irradiated fuel assembly. The mechanical features of the RRTN are the same as those for the RTN (see Figure 4.2-2) or the WIN with some minor dimensional differences in the top nozzle adapter plate thimble hole to facilitate attachment to an irradiated fuel assembly. The RRTN design contains hold-down springs and screws made of Inconel 718, whereas, other components are made of Type 304 stainless steel.

Guide and Instrument Thimbles

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

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

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

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

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

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

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

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective clad temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data as shown in Table 4.3-6 and Doppler coefficient data as shown on Figure 4.3-32. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (see Section 4.3.2.8). It can be seen that Doppler defect data is typically within 0.2 percent $\Delta\rho$ of prediction.

ALPHA/PHOENIX/ANC has two Doppler models - a Doppler power model and a Doppler temperature model. The default Doppler model in APA is the temperature model and is based on a fit of fast absorption cross sections against the fuel temperature at 0, 1, and 2 times the reference power. In NEXUS/ANC9, the effects of fuel temperature are captured on all the cross sections directly, as it is one of the fundamental parameters used to fit cross sections.

4.3.3.2 Macroscopic Group Constants

There are lattice codes which have been used for the generation of macroscopic group constants needed in the spatial, few-group diffusion codes. One is a version of the LEOPARD and CINDER codes, which has historically been the source of the macroscopic group constants. The others are PHOENIX-P and PARAGON, which are used in present reload designs (Reference 30 and 38). The NEXUS methodology (Reference 39) is a reparameterization of the PARAGON nuclear data output. The NEXUS methodology provides a linkage between PARAGON and ANC, establishing a new code system, while still using PARAGON.

Macroscopic few-group constants and analogous microscopic cross sections (needed for feedback and microscopic depletion calculations) were previously generated for fuel cells by a version of the LEOPARD (Reference 15) and CINDER (Reference 16) codes, which are linked internally and provide burnup dependent cross sections. Normally a simplified approximation of the main fuel chains is used; however, where needed, a complete solution for all the significant isotopes in the fuel chains from Th-232 to Cm-244 is available (Reference 20). Fast and thermal cross section library tapes contain microscopic cross sections taken for the most part from the ENDF/B (Reference 21) library, with a few exceptions where other data provide better agreement with critical experiments, isotopic measurements, and plant critical boron values. The effect on the unit fuel cell of non-lattice components in the fuel assembly is obtained by supplying an appropriate volume fraction of these materials in an extra region which is homogenized with the unit cell in the fast (MUFT) and thermal (SOFOCATE) flux calculations. In the thermal calculation, the fuel rod, clad, and moderator are homogenized by energy-dependent disadvantage factors derived from an analytical fit to integral transport theory results.

Group constants for discrete burnable absorber cells, guide thimbles, instrument thimbles, and interassembly gaps are generated in a manner analogous to the fuel cell calculation. Reflector group constants are taken from infinite medium LEOPARD calculations. Baffle group constants are calculated from an average of core and radial reflector microscopic group constants for stainless steel.

Group constants for control rods are calculated in a linked version of the HAMMER (Reference 22) and AIM (Reference 23) codes to provide an improved treatment of self shielding in the broad resonance structure of these isotopes at epithermal energies than is available in LEOPARD. The Doppler broadened cross sections of the control rod materials are represented as smooth cross sections in the 54-group LEOPARD fast group structure and in 30 thermal groups. The four-group constants in the rod cell and appropriate extra region are generated in the coupled space-energy transport HAMMER calculation. A corresponding AIM calculation of the homogenized rod cell with extra region is used to adjust the absorption cross sections of the rod cell to match the reaction rates in HAMMER. These transport-equivalent group constants are reduced to two-group constants for use in space-dependent diffusion calculations. In discrete X-Y calculations only one mesh interval per cell is used, and the rod group constants are further adjusted for use in this standard mesh by reaction rate matching the standard mesh unit assembly to a fine-mesh unit assembly calculation.

Validation of the cross section method is based on analysis of critical experiments as shown in Table 4.3-7, isotopic data as shown in Table 4.3-8, plant critical boron (C_B) values at HZP, BOL, as shown in Table 4.3-9 and at HFP as a function of burnup as shown on Figures 4.3-33 through 4.3-35. Control rod worth measurements are shown in Table 4.3-10.

Confirmatory critical experiments on discrete burnable absorbers are described in Reference 24.

PHOENIX-P has been approved by the USNRC as a lattice code for the generation of macroscopic and microscopic few group cross sections for PWR analysis (Reference 30). PHOENIX-P is a two-dimensional, multigroup, transport-based lattice code capable of providing all necessary data for PWR analysis. Since it is a dimensional lattice code, PHOENIX-P does not rely on predetermined spatial/spectral interaction assumptions for the heterogeneous fuel lattice and can provide a more accurate multigroup flux solution than versions of LEOPARD/CINDER.

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (Reference 30).

First, a two-dimensional fine energy group nodal solution is obtained, coupling individual subcell regions (pellet, clad, and moderator) as well as surrounding pins, using a method based on Carlvik's collision probability approach and heterogeneous response fluxes which preserve the heterogeneity of the pin cells and their surroundings. The nodal solution provides an accurate and detailed local flux distribution, which is then used to homogenize the pin cells spatially to fewer groups.

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

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

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

PARAGON is a two-dimensional multi-group neutron (and gamma) transport code. It is an improvement over the Westinghouse licensed code PHOENIX-P (Reference 30). The main difference between PARAGON (Reference 38) and PHOENIX-P resides in the flux solution calculation. PHOENIX-P uses a nodal cell solution coupled to an S4 transport solution as described in Reference 38. PARAGON uses the Collision Probability theory within the interface current method to solve the integral transport equation. Throughout the whole calculation, PARAGON uses the exact heterogeneous geometry of the assembly and the same energy groups as in the cross-section library to compute the multi-group fluxes for each micro-region location of the assembly.

In order to generate the multi-group data that will be used by a core simulator code PARAGON goes through four steps of calculations: resonance self-shielding, flux solution, homogenization and burnup calculation. PARAGON can provide nuclear data, both cross sections and pin power information, to a core simulator code such as ANC.

The NEXUS methodology (Reference 39) is a reparameterization of the PARAGON nuclear data output (cross sections) and a new reconstruction approach with the ANC core simulator code to simplify the use of this code system for design use. The NEXUS methodology provides a linkage between PARAGON and ANC, establishing a new code system, while still using PARAGON. The NEXUS approach is to account for the spectral changes by parameterizing the cross section output of PARAGON, such that the cycle specific boron letdown curves do not need to be provided in the analysis. The parameterization adequately accounts for the relevant neutronic effects of temperature feedback, fuel depletion, burnable poisons, boron concentrations, and fission products.

The NEXUS methodology (Reference 39) approach uses a calculational matrix of lattice code calculations performed with PARAGON to form a set of data in order to parameterize the cross sections according to a spectral index (SI), the moderator temperature (Tm), and the fuel temperature (Tf). These parameters, in conjunction with nuclide tracking during irradiation, allow for feedback-free cross sections, and correction functions to be generated. The lattice calculations are performed using a base-line reference depletion case with several branches to account for the effects of different local conditions, thus providing a data set that covers a wide range of potential local conditions ranging from those typical of a cold shutdown reactor condition to full power conditions. The SI is based on the ratio of the epithermal to thermal neutron flux and is a measure of the local neutron spectrum. The Tm and Tf dependences account for changes in moderation and resonance absorption respectively. These parameters are used to develop a series of correction factors to account for these physical effects using a multivariable least-squares technique. The correction factors are dependent on the differences between the nodal values for these parameters and the values used in the reference lattice depletion calculations. The effects of xenon, actinides, other fission products, and burnable absorbers are directly accounted for by first tracking the number density of each isotope directly, thereby accounting for explicitly for fuel depletion. The macroscopic cross sections themselves are reconstructed based on these number densities and the microscopic cross section for each particular isotope given the nodal conditions. The microscopic cross sections in these cases are adjusted by correction functions based on local nodal parameters.

4.3.3.3 Spatial Few-Group Diffusion Calculations

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

Discrete X-Y calculations (1 mesh per cell) were carried out to determine critical boron concentrations and power distributions in the X-Y plane.

An axial average in the X-Y plane was obtained by synthesis from unrodded and rodded planes. Axial effects in unrodded depletion calculations were accounted for by the axial buckling, which varies with burnup and is determined by radial depletion calculations which are matched in reactivity to the analogous R-Z depletion calculation. The moderator coefficient is evaluated by varying the inlet temperature in the same X-Y calculations used for power distribution and reactivity predictions.

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

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

Recent few-group spatial calculations have input PHOENIX-P or PARAGON supplied two-group cross-sections to the Advanced Nodal Code (ANC). ANC is a two-group, two or three-dimensional nodal code capable of determining typical nuclear design analyses, such as critical boron concentrations, average assembly and pin powers, control rod worths, reactivity coefficients, assembly and pin burnups and axial power distributions. Through the use of advanced nodal techniques, ANC is able to produce solutions similar to the fine mesh, finite difference diffusion theory codes such as TURTLE/TORTISE. ANC has been benchmarked against TORTISE (an improved version of TURTLE) for normal and off-normal conditions, such as ejected rod, stuck rod and dropped rod (Reference 31). The qualification of the PHOENIX-P/ANC methodology against measured data is given in Reference 30. The qualification of the PARAGON/ANC methodology against measured data is given in Reference 38. The qualification of the NEXUS/ANC methodology against measured data is given in Reference 39. The qualification of new pin power recovery methodology can be found in Reference 40.

Validation of the spatial codes for calculating power distributions involves the use of in-core and ex-core detectors and the BEACON core monitoring system (PDMS) and is discussed in Section 4.3.2.2.7. Note that BEACON (Reference 37) was affirmed for continued use with the USNRC approved Westinghouse design model methodologies PHOENIX-P/ANC, PARAGON/ANC, and NEXUS/ANC.

4.3.3.4 Pin Power Reconstruction

The conventional methodology implemented in ANC calculates the homogeneous pin power distribution and applies the group-wise pin power form factors (these were referred to as "pin factors") to obtain the final pin power. The conventional methodology has shown historically that it can predict the pin power with high accuracy for traditional PWR cores, which are operated without significant insertion of control rod banks. With the introduction of new PWR core designs control rods may be inserted into the core during operation, which may significantly change the heterogeneity of the fuel assemblies. Since the conventional methodology used in ANC does not include the control rod history effect on the pin factors, the pin power distribution is not as accurate when control rods are inserted for significant periods of time during operation. This is particularly true for high-worth control rods. Moreover, because the control rod insertion and withdrawal strategy is not pre-determined, conventional pin power methodology has difficulty in capturing the heterogeneity change and the accumulated history impact on the pin power distribution. This limitation is overcome by the new methodology (Reference 40), which directly follows the history of each individual fuel rod in ANC and computes the fuel rod macroscopic cross-sections based on the fuel rod history and the local spectrum. Therefore, the new methodology enables ANC to calculate the effect of control rod insertion during operation on pin power distribution while maintaining the same accuracy as the conventional method for a traditional core.

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

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

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A preliminary estimate of the leakage can be obtained from the rate of condensate flow increase during the transient; a better estimate can be made from the steady state condensate flow at equilibrium conditions. The device alarms on a 0.06 gpm condensate flow rate, which indicates that a 1 gpm or larger leak has been developing for about 5 minutes.

The system can be checked during reactor shutdown.

5.2.7.1.5 Intersystem Leakage Detection

The following provisions are available for the detection of intersystem leakage from the RCS:

1. Radiation monitors are provided for the Steam Generator Blowdown System, each Main Steam Line and condenser air removal effluent line which alert the operator to reactor coolant leakage into the Main Steam and Feedwater Systems from steam generator tube leaks.

2. Radiation monitors are provided for the Component Cooling System to detect reactor coolant leakage into the system from the Residual Heat Removal System. Surge tank level is also an indicator for leakage detection.

3. The accumulators are isolated from the RCS by two check valves. They are also provided with a remote manual valve. Leakage would be detected by level and pressure changes in the accumulators.

4. The high-head SIS line is isolated from the RCS by two check valves and normally closed remote manual valves. Leakage from the RCS, that would pass the normally closed SJ12/SJ13 gate valves, would be detected by pressure changes in the line.

5. The Residual Heat Removal System and the Intermediate Head SIS are isolated from the RCS by two check valves and normally closed remote manual valves. Leakage would cause operation of the relief valves which discharge to the containment sump.

RCS leakage can also be detected by level changes in the volume control tank, as well as by RCS water inventory balances, which are performed periodically. The indications identified above are provided, with appropriate alarms, in the control room.

5.2.7.2 Indication in Control Room

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

5.2.8 Inservice Inspection Program

Preservice and inservice inspection for Class 1, 2, and 3 components are in accordance with the rules of 10CFR50.55(a), Paragraph (g) to the extent practical. Relief from the applicable ASME Section XI inspection requirements have been transmitted to the NRC through the Inservice Inspection Program Long Term Plans and Testing Programs.

There are no other credible sources of shaft seizure other than impeller rubs. Sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin (or pins for the RCPs which have installed the upgrade No. 1 RCP SIGMA Seal) in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Protective relays are provided to trip the supply breaker on an overcurrent condition during startup and normal operation. Indication of pump malfunction is provided by the following alarms: bearing water high temperature, excessive Number 1 seal leakoff, and excessive pump vibration. If a pump malfunction is indicated, the affected pump is taken out of service for investigation.

5.5.1.3.6 Critical Speed

The RCP shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.5.1.3.7 Missile Generation

Precautionary measures taken to preclude missile formation from RCP components assure that the pumps will not produce missiles under any anticipated accident conditions. Each component of the pump is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller, because the small fragments that might be ejected would be contained by the heavy casing.

5.5.1.3.8 Pump Cavitation

The minimum NPSH required by the RCP at best estimate flow is approximately 170 feet (approximately 85 psi). In order for the controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 200 psi across the Number 1 seal. This corresponds to a primary loop pressure at which the minimum NPSH requirement is exceeded and no limitation on pump operation occurs from this source.

5.5.1.3.9 Pump Overspeed Considerations

For turbine trips actuated by either the Reactor Trip System or the Turbine Protection System, the generator breaker disconnects the generator permitting the RCPs to remain connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the Turbine Control System and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the Turbine Protection System has a mechanical overspeed protection trip, usually set at about 110 percent of turbine speed. In case a generator trip deenergizes the pump buses, the RCP motors are transferred to offsite power within six to ten cycles.

5.5.1.3.10 Anti-Reverse Rotation Device

Each of the RCPs is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and two shock absorbers.

After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable plant experience with the anti-reverse rotation device has shown high reliability of operation.

5.5.1.3.11 Shaft Seal Leakage

During normal operation, leakage along the RCP shaft is controlled by three shaft seals arranged in series. Charging flow is directed to each RCP via a seal water injection filter. It enters the pump and is directed to a point between the pump shaft bearing and the pump seals. The flow splits and a portion flows down the shaft through and around the lower radial bearing, down past the thermal barrier heat exchanger and into the RCS; the remainder flows up the pump shaft annulus and provides a back pressure on the Number 1 seal and a controlled flow through the seal. Above the seal, most of the flow leaves the pump via the Number 1 seal leak-off line. Minor flow passes through the Number 2 seal and its leak-off line, and through the Number 3 seal and its leak-off line.

Hydrogen concentration is measured by a hydrogen partial pressure sensor in conjunction with a total pressure sensor. The partial pressure sensor is galvanic in nature, consisting of a platinum black electrode and a platinum oxide counter electrode within a polysulfone housing.

The range of measurement is 0 to 10 volume percent with an accuracy of 2 percent of full scale. Output is displayed in one Control Room. Alarms are provided for high hydrogen concentration, power failure, system error, and calibration mode.

Power is supplied from vital sources.

In addition to the Hydrogen Monitoring System, hydrogen concentration may be determined by taking a grab sample using the containment air particulate detector (APD) skid.

In amendments 281 and 264 to Salem Units 1 and 2 Operating Licenses, a commitment was made to maintain the capability for the hydrogen monitoring system for diagnosing beyond design basis accidents. The functionality requirements of the containment hydrogen analyzers are contained in the Salem Technical Requirements Manual.

6.2.6 References for Section 6.2

1. Field, C. V., "Fan Cooler Motor Unit Test," WCAP-7829, April 1972.

2. Styrikovich, M. A. et al., "Attomnoyl Energiya," Volume 17, No. 1, pp. 45-49, (Translation in UDE - 621.039.562.5), July 1964.

3. Parsley, Jr., L. F., "Design Considerations of Reactor Containment Spray Systems - Part VI." ORNL-TM-2412. Part 6, 1969.

4. Parsley, Jr., L. F., "Design Considerations of Reactor Containment Spray Systems - Part VII." ORNL-TM-2412, Part 7, 1970.

5. Eggleton, A. E. J., "A Theoretical Examination of Iodine-Water Partition Coefficient," AERE (R) - 4887, 1967.

LIST OF TABLES (Cont)

LIST OF FIGURES

For the postulated abnormal conditions, the exact combination of conditions (reactor coolant pressure, temperature and core power, instrumentation inaccuracies, etc.) will not cause a DNBR to go below 1.30 before a reactor trip. The simultaneous loss of power to all of the reactor coolant pumps is the accident condition most likely to approach a DNBR of 1.30 for the calculated worst fuel rod. In any event, the DNBR is near 1.30 for only a few seconds.

The ΔT trip functions are based on the differences between measured hot leg and cold leg temperatures. These differences are proportional to core power.

The ΔT trip functions are provided with a nuclear differential flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse axial distribution which could lead to exceeding the allowable core conditions.

In the event of a difference between the upper and lower ion chamber signals that exceeds the desired range, automatic feedback signals are provided to reduce the overpower-overtemperature trip setpoints, which in turn block rod withdrawal and reduce the load to maintain appropriate operating margins.

7.2.3.2 Specific Control and Protection Interactions

Nuclear Flux

Four power-range nuclear flux channels are provided for overpower protection. Isolated outputs from all four channels are auctioneered for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection. Two-out-of-four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, the Control System will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are compensated by the temperature control signals.

Coolant Temperature

One hot-leg and one cold-leg temperature reading is provided from each coolant loop to use for protection. Narrow-range thermowell resistance temperature detectors (RTDs) are provided for each coolant loop. In the hot legs, sampling scoops are used because the flow is stratified; that is, the fluid temperature is not uniform over a cross section of the hot leg. One dual-element RTD is mounted in each of the three sampling scoops associated with each hot leg. The scoops extend into the flow stream at locations 120 degrees apart in the cross-sectional plane. Each scoop has five orifices which sample the hot-leg flow along the leading edge of the scoop. Outlet ports are provided in the scoops to direct the sampled fluid past the sensing element of the RTDs. One of each RTD's dual elements is used for protection, while the other is an installed spare. Three protection readings from each hot leg are averaged to provide a hot-leg reading for that loop.

One dual-element RTD is mounted in a thermowell associated with each cold leg. No flow sampling is needed because coolant flow is well mixed by the reactor coolant pumps. As is the case with the hot leg, one element is used while the other is an installed spare.

Certain control signals are derived from individual protective channels through isolation amplifiers. The isolation amplifiers are classified as part of the protective system. The reactor control system uses the highest of four isolated T_{avg} signals.

The RTDs are a fast-response design which conforms to applicable IEEE standards and 10CFR50.49 requirements.

The main requirement for reactor protection is that the temperature difference between the hot leg and cold leg varies linearly with power. All ΔT setpoints are in terms of the full power ΔT; thus, absolute ΔT measurements are not required. Linearity of ΔT with power will be verified during startup tests.

Reactor protection logic using reactor coolant loop temperatures is 2/4, with one channel per reactor coolant loop. This complies with all applicable IEEE Standard 279-1971 criteria.

Since reactor control is based on the highest average temperature from the four loops, the control rods are always moved based upon the most pessimistic temperature measurement with respect to margins to DNB. A spurious low average temperature measurement from any loop temperature control channel will cause no control action. A

spurious high average temperature measurement will cause rod insertion (safe direction).

Channel deviation signals in the Control System will give an alarm if any temperature channel deviates significantly from the auctioneered (highest). Automatic rod withdrawal blocks will also occur if any one of four nuclear channels indicates an overpower condition, or if any two of four temperature channels indicate an overtemperature or overpower condition. Although automatic rod withdrawal is disabled, the automatic rod withdrawal blocks remain. Two-out-of-four (2/4) trip logic is used to ensure that an overtemperature or overpower ΔT trip will occur if needed, even with an independent failure in another channel. Finally, as shown in Section 15.1, the combination of trips on nuclear overpower and high pressurizer pressure also serves to limit an excursion for any rate of reactivity insertion.

TABLE 7.2-2 (Cont)

Designation	Derivation	Function
C-1	1/2 Neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal*
C-2	1/4 Neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal*
C-3	2/4 Over-temperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal* Actuates turbine runback via load reference
C-4	2/4 Overpower ΔT above setpoint	Blocks automatic and manual control rod withdrawal* Starts turbine runback via load reference
C-5	1/1 Turbine steamline inlet pressure below setpoint	Blocks automatic control rod withdrawal*
C-6	1/2 Turbine steamline inlet pressure below setpoint	Blocks turbine runback via load limit
C-7	1/1 Time derivative (absolute value) of turbine steamline inlet pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation

* Automatic rod withdrawal is disabled

TABLE 7.5-4 (Cont)

Variable Ref. No.	Variable Description	Compliance Level
17	Containment Hydrogen Concentration - Analyzers	3a
18	Containment Effluent Radioactivity Noble Gases from Identified Release Points - Monitors	3b
19	Deleted	
20	RHR System Flow - Transmitters	3a
21	RHR Heat Exchanger Outlet Temperature - Thermocouples	4b
22	Accumulator Tank Level and Pressure - - Transmitters - Transmitter Range	
23	Accumulator Isolation Valve Position	1
24	Boric Acid Charging Flow - Transmitters	Unit 1-3a Unit 2-1
25	Flow in HPI System - Transmitters	3a
26	Flow in LPI System - Transmitters	3a
27	Refueling Water Storage Tank Level and Low Level Alarm - Transmitters	Unit 1-3a Unit 2-1
	- Transmitter Range	Unit 1-4c Unit 2-1
28	Reactor Coolant Pump Status	1
29	Primary System Safety Relief Valve Positions (including PORV and code valves) or Flow through or Pressure in Relief Valve Lines	1
30	Pressurizer Level - Transmitters	Unit 1-3a Unit 2-1
	- Transmitter Range	Unit 1-4c Unit 2-1
31	Pressurizer Heater Status (Current) - Heaters	2

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The Nuclear Steam System's controls for the Salem Generating Station and the D. C. Cook Plant are functionally the same.

7.7.1 Design Basis

7.7.1.1 Reactor Control System

The Reactor Control System is designed to reduce nuclear plant transients for the design load perturbations, so that reactor trips will not occur for these load changes.

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

The function of the Reactor Control System is to provide automatic insertion* of the RCCAs during power operation of the reactor. The system uses input signals including neutron flux, coolant temperature, and turbine load. The Chemical and Volume Control System (CVCS)(Section 9) supplements the Reactor Control System by the addition and removal of varying amounts of boric acid solution.

There is no provision for a direct continuous visual display of primary coolant boron concentration. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to power and average coolant temperature. There is a direct relationship between control rod position and power, and it is this relationship which establishes the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints to alert

* Automatic Rod Withdrawal is disabled

the operator to take corrective action in the event a control group approaches or reaches its lower limit.

Any unexpected change in the position of the control group under automatic control, or a change in coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples are taken for determination of the coolant boron concentration. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

The Reactor Control System is designed to enable the reactor to follow load changes automatically when the output is above approximately 15 percent of nominal power. Control rod positioning may be performed automatically when plant output is above this value, and manually at any time.

Automatic Rod Withdrawal is disabled. Automatic control rod positioning is limited to rod insertion. The operator is able to select any single bank of rods for manual operation. This is accomplished with a multiposition switch so that he may not select more than one bank. He may also select automatic or manual reactor control, in which case the control banks can be moved only in their normal sequence with some overlap as one bank reaches its full withdrawal position and the next bank begins to withdraw.

The system enables the nuclear unit to accept a step load increase of 10 percent and a ramp increase of 5 percent per minute within the load range of 15 percent to 100 percent without reactor trip subject to possible xenon limitations. Similar step and ramp load reductions are possible within the range of 100 percent to 15 percent of nominal power. The Steam Dump System permits the plant to accept an additional 40-percent load reduction without reactor or turbine trip.

The Reactor Control System is capable of restoring coolant average temperature to within the programmed temperature deadband, following a scheduled or unexpected change in load. Automatic Rod Withdrawal is disabled. Only automatic rod insertion is available to restore coolant average temperature.

The pressurizer water level is programmed to be a function of the auctioneered coolant average temperature. This is to minimize the requirements on the CVCS and Waste Disposal System (WDS) resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed without actuating the steam generator safety valves by means of controlled steam dump to the condenser and by injection of auxiliary feedwater into the steam generators. Reactor Coolant System (RCS) temperature is reduced to the no load condition. This no load coolant temperature is maintained by steam dump to the condensers which removes residual heat.

7.7.1.2 Operating Control Stations

The Salem Generating Stations have a common Control Room with separate control stations for each unit, as shown on Plant Drawing 204803. The Control Rooms are located in the Auxiliary Building. The information presented in this section pertains to both Control Rooms, although only one is described.

Each unit is equipped with separate Control Stations which contain those controls and instrumentation necessary for operation of that unit under normal and abnormal conditions. The Control Room is continuously occupied by the operating personnel under all operating conditions. Equipment in this area had been designed to minimize the possibility of a condition which could lead to inaccessibility or evacuation.

Control Room shielding and ventilation are designed such that the occupants of the room shall not receive doses in excess of 5 rem

to the whole body, or its equivalent to any part of the body, during the course of a Loss-of-Coolant Accident (LOCA). This includes doses received during ingress and egress. The Control Room Air Conditioning System is described in Section 9.

The Control Room is designed to be continuously occupied by qualified operating personnel under all operating and Design Basis Accident (DBA) conditions. Both Control Rooms share a number of separate Communication Systems. One system consists of direct dialing telephones. Another independent Communication System is a party line and voice paging system which provides the primary means of communication between plant operations personnel throughout the station. Battery-operated portable two-way transceivers are provided for special purposes. There is a separate system interconnecting the Containment Building, Control Room and refueling area. These systems are energized from inverter powered buses.

The capability to bring the reactor to a hot shutdown condition is provided at locations outside the Control Room. The majority of equipment for this condition is located in the auxiliary feedwater pump area.

7.7.2 System Design

Two independent Control Systems of different principles provide redundancy of reactivity control. One of the two Reactivity Control Systems employs RCCAs to regulate the position of the neutron absorbers within the reactor core. The other Reactivity Control System employs the CVCS to regulate the concentration of boric acid solution neutron absorber in the RCS. These systems are described in Sections 3 and 9, respectively.

The Reactor Control System is designed to provide stable system control over the full range of automatic operation throughout core life without requiring operator adjustment of setpoints other than normal calibration.

A simplified block diagram of the Reactor Control System is shown on Figure 7.7-1. The Reactor Control System controls the reactor coolant average temperature by regulation of control rod bank position. The system is capable of restoring reactor coolant average temperature to the programmed value following a change in load. The programmed coolant average temperature increases linearly from zero power to the full power condition.

The Reactor Control System will also initially compensate for reactivity changes caused by fuel depletion and/or xenon transients. Long-term compensation for these two effects is periodically made by adjustment of the boron concentration to return the control rod bank to its normal operating range.

The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. The error between the programmed average temperature and the highest of the measured average temperatures from each of the reactor coolant loops constitutes the primary control signal as shown on Figure 7.7-1. An additional control input signal is derived from the reactor power vs. turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transients peaks. From these input signals, the rod direction command signals are derived. The rod speed command signal varies over the corresponding range of 3.75 to 45 inches per minute depending on the magnitude and the rate of change of the input signals. The rod direction command signal is determined by the positive or negative value of the temperature difference signal. The rod speed and rod direction command signals are fed to the Rod Control System.

7.7.2.1 Rod Cluster Control Assembly Arrangements

There are 53 RCCAs divided into four shutdown banks of 24 RCCAs and four control banks of 29 RCCAs. The control banks are the only rods that can be manipulated under automatic control. Automatic Rod Withdrawal is disabled. Only Automatic Rod Insertion is available. The control rods are divided into groups to obtain smaller incremental

reactivity changes per step. All RCCAs in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

7.7.2.2 Rod Control

For a complete description of rod control and position indication systems, see References 1, 2 and 3.

7.7.2.2.1 Control Bank Rod Insertion Monitor

The purpose of the control bank rod insertion monitor is to give warning to the operator of a decrease in shutdown margin. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased with increasing power. One parameter which is proportional to power is used an input to the insertion monitor. This is the ΔT between the hot leg and the cold leg, which is a direct function of reactor power. The rod insertion monitor uses this parameter for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{auct}$$

where:

Z_{LL} = maximum permissible insertion limit for affected control bank

$(\Delta T)_{auct}$ = highest ΔT for all four loops

A, C = constants chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations

This circuit prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensate auctioneered T_{avg} and the reference T_{avg} and is based on turbine steamline inlet pressure.

The T_{avg} signal is the same as that used in the RCS. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available in this situation, steam dump terminates as the error comes within the maneuvering capability of the control rods.

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The purpose of the Steam Dump System is to reduce RCS transients following a substantial turbine load reduction by bypassing main steam directly to the condenser, thereby maintaining an artificial load on the steam generators. The Control Rod System can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

Following a reactor and turbine trip, decay heat and sensible heat stored in the reactor coolant are removed without actuating the steam generator safety valves by means of controlled steam dump to

the condenser and by injection of feedwater to the steam generators.

Following a turbine trip, as monitored by the turbine trip signal, the load rejection steam dump controller is defeated and the turbine trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead/lag compensated auctioneered T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined setpoint, the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude indicating that the RCS T_{avg} is being reduced toward the reference no load value, the dump valves are modulated by the plant trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

The error signal determines whether a group of valves is to be tripped open or modulated open. In either case, they are modulated when the error is below the trip-open setpoints.

7.7.2.8 <u>In-core Instrumentation</u>

The in-core instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information thus obtained, it is possible to confirm the reactor core design parameters.

The functionality requirements for the in-core instrumentation are contained in the Salem Technical Requirements Manual.

7.7.2.9 Operating Control Stations

The Control Room provides the necessary controls and indication to start, operate and shut down the unit with sufficient redundant information displays and alarm indications to ensure safe and reliable operation under all normal and abnormal conditions.

The most important unit controls are located on the control console, which is of freestanding, horseshoe shaped design, constructed of steel. The front horizontal portion contains the most frequently used operating controls while the rear vertical portion contains less frequently used controls and indicators.

Controls and indicators are functionally grouped on a system basis to facilitate safe, reliable operation of the unit during transients as well as normal operation. Those systems requiring more frequent operator attention are located in the central area, while less frequently used controls are located on either side.

Most of the console instruments consist of plug-in, back-lighted pushbutton stations and vertical scale indicators. Operator action consists of a momentary push of a button. The lights in the buttons are used for status, information and alarm indication.

Alarms are provided in the Control Room to alert the operator of abnormal plant conditions. The alarm displays are located either on a console pushbutton control station, where corrective action would be taken, or on the overhead annunciator. An alarm signal causes a back-lighted pushbutton to flash and the console audible alarm to sound until acknowledged by the operator. Upon clearing of an alarm condition, the console audible ringback is sounded. Other alarms are displayed on an annunciator panel located overhead above the console. This panel consists of illuminated windows and separate audible alarm and ringback tones. Two first-out annunciator panels indicate, by means of red and white lights, the first reactor or turbine trip to occur. A comprehensive status panel, employing the same type of illuminated windows as the console, indicates the condition of trip channels and alarms. By means of a "mimic bus" arrangement, the interaction of trip conditions and permissives can be quickly analyzed. Diesel generator automatic load sequencing, critical valve status and other important information are also clearly displayed.

A computer is employed to assist the operator and to monitor the unit. Selected parameter trends can be recorded while alarm conditions are indicated to the operator. The computer output consists of a video display mounted on the console, logging printer mounted on Control room panels located convenient to the plant operators. The video display and printers are independent devices.

Vertical panels form the walls of the Control Room and contain controls for systems, which require only occasional operator attention as well as miscellaneous recorders and indicators.

Reliability and ease of service has been designed into the Control Room. The majority of the console instruments are plug-in modules. In the unlikely case that a pushbutton station or indicator on the console malfunctions, it can be readily removed and replaced from the front of the console. No access to the inside of the console is needed. Re-lamping can also be quickly accomplished from the front of the pushbutton.

7.7.2.11 Residual Heat Removal Performance Monitoring System

The residual heat removal performance monitoring system provides an early warning of loss of decay heat removal capabilities. The system includes:

1. Two independent narrow range continuous Reactor Coolant System level indications and wide range RCS level indication whenever the RCS is in a reduced inventory (mode 5 or 6). The narrow level range monitored is from Elevation 97' to Elevation 91.1'. The wide range level is monitored from elevation 97 feet to 109.5 feet. The wide range midloop level is used while reactor vessel level is above the narrow range midloop level indication.

2. Other monitoring capability:
   a. RHR pump discharge flow
   b. RHR pump discharge pressure
   c. RHR pump suction pressure
   d. RHR pump motor current

   The system is shown on the RCS and RHR system drawings (Plant Drawings 205301 and 205332).

The system is designed to accurately monitor water level while the RHR system is operating with the RCS drained to the mid level of the RPV nozzles. This level allows draining of the steam generators but establishes a very narrow operating level over which the RHR pumps will have adequate NPSH. The Reactor Vessel Level Indicating System (Plant Drawing 205332) provides a wide range level indication but is not accurate enough for the purposes described in NRC Generic Letter 88-17.

The testing design criteria are the same as used for instruments that are connected to full reactor temperature and pressure. The channel design and physical location of the transmitters prevent any physical damage from a refueling seal failure even though the system is not specifically designed to function while flooded or over this range. The low side of the level transmitter is connected to the pressurizer and can be manually aligned to measure the static water level in the vessel with or without pressure in the vessel.

The system is not required for safe shutdown, and is used only during cold shutdown, therefore, it is not safety related. However, it is designed, installed, and maintained as if it were safety related.

7.7.2.12 Seismic Monitoring Instrumentation

The operability of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability

is required to permit comparison of the measured response to that used in the design basis for the facility. The functionality requirements for the seismic monitoring instrumentation are contained in the Salem Technical Requirements Manual.

7.7.2.13 Meteorological Monitoring Instrumentation

The meteorological instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. The functionality requirements of the meteorological monitoring instrumentation are contained in the Salem Technical Requirements Manual.

7.7.3 System Design Evaluation

7.7.3.1 Unit Stability

The Rod Control System is designed to limit the amplitude and the frequency of continuous oscillation of coolant average temperature about the Control System setpoint within acceptable values. Continuous oscillation can be induced by the introduction of a feedback control loop with an effective loop gain which is either too large or too small with respect to the process transient response, i.e., instability induced by the control system itself. Because stability is more difficult to maintain at low power under automatic control, no provision is made to provide automatic control below 15 percent of full power.

The Control System is designed to operate as a stable system over the full range of automatic control throughout core life.

7.7.3.2 Step Load Changes Without Steam Dump

A typical power control requirement is to restore equilibrium conditions, without a trip, following a plus or minus 10 percent step change in load demand, over the 15 to 100 percent power range for automatic control. The design must necessarily be based on conservative conditions and a greater transient capability is expected for actual operating conditions. A load demand greater than full power is prohibited by the turbine control load limit devices.

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TABLE 7.7-4

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TABLE 7.7-5

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TABLE 7.7-6

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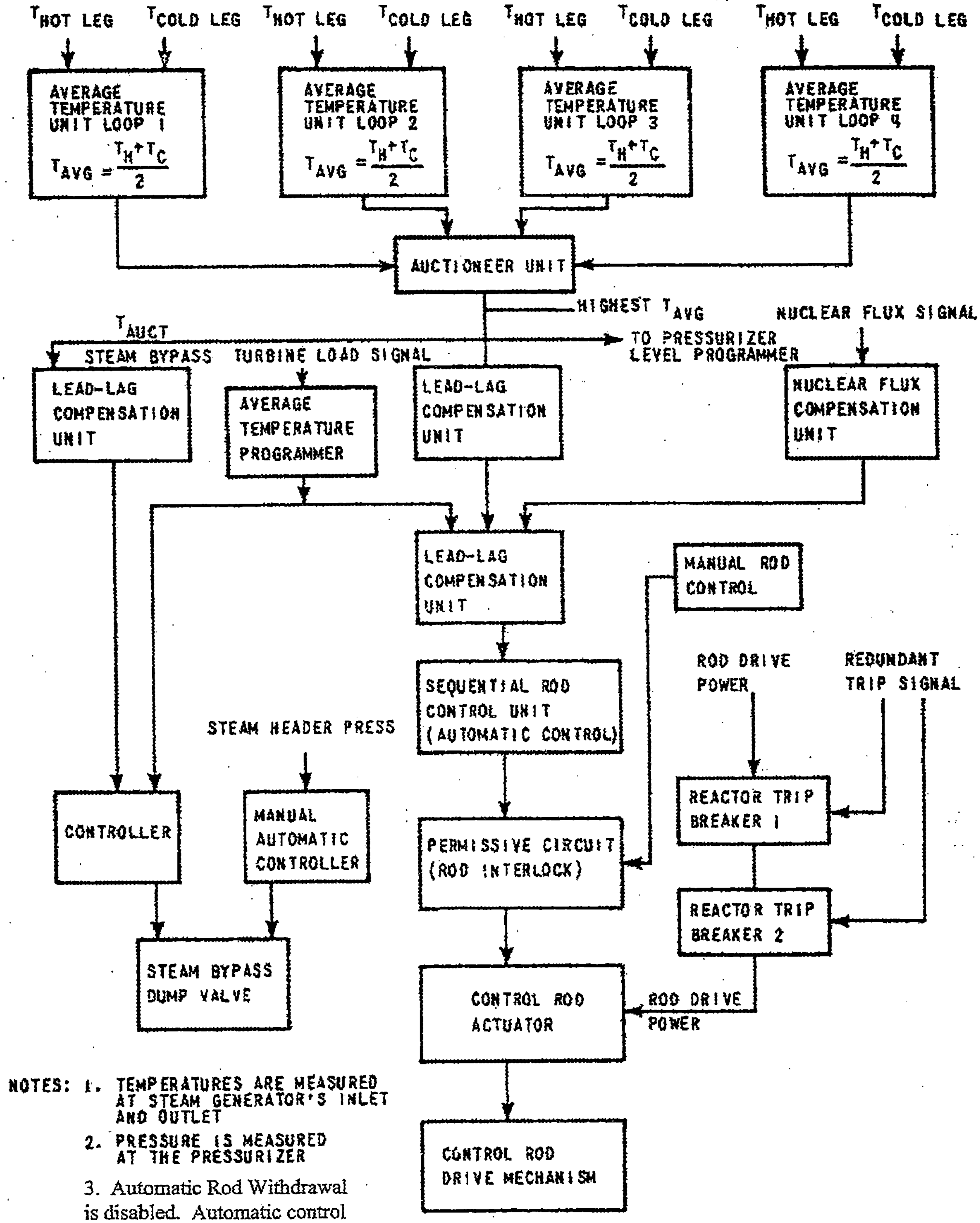

NOTES:
1. TEMPERATURES ARE MEASURED AT STEAM GENERATOR'S INLET AND OUTLET
2. PRESSURE IS MEASURED AT THE PRESSURIZER
3. Automatic Rod Withdrawal is disabled. Automatic control will only insert rods.

PSEG Nuclear LLC SALEM NUCLEAR GENERATING STATION	BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM
	Updated FSAR REV 31 DECEMBER 05, 2019 — Figure 7.7-1

TABLE 9.1-4 (Cont)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location (ft)	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/ Components Involved in Dropped Lift
		Containment Building Elevation 130	RCP Motor Access Plugs	30,000	60	
		Containment Building Elevation 130	RCP Motor	77,000	60	
		Containment Building Elevation 130	RCP Motor Flywheel	14,250	60	
Polar Crane Jib		Containment Building Elevation 130	Equipment Hatch	23,300	N/A	
Mobile Cherry Pickers (2)	12.5 15	Containment Building Elevation 130	Stud Rack with 9 RPV Head Studs	7,000	N/A	
Demineralizer & Ion Exchanger Service Monorail	6	Auxiliary Building Elevation 122	Lead Filled Plugs	10,000	22 above El. 102' 1½ above El. 122'	CVC system control cables running in Trays 1A418, 1A420,2A418, 2A420, Drawing 205841.
			Concrete Floor Plugs	5,000	2	

TABLE 9.1-4 (Cont)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location (ft)	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/ Components Involved in Dropped Lift
			Hittman Casks Lid	9,500	2½ Area A	
			Portable Demin	9,000	14 Area B	
Auxiliary Feedwater Pumps Monorails	1.65	Auxiliary Building Elevation 84	Motor Driven Pump	4,400	3	Redundant air supply
			Turbine Driven Pump	3,300	3	
Charging Pump Monorails	2.45	Auxiliary Building Elevation 84	Upper Centr. Charging Pump Casing	4,900	3 1/2	Associated CVC piping and waste decon. tanks on the elevation below.
			Recip. Charging Pump Motor	1,500	3 1/2	
			Recip. Charging Pump Coupling	6,000	5	
Component Cooling Pump Monorails	1.6	Auxiliary Building Elevation 84	Component Cooling Pump Motor	2,650	8	There may be occasion to lift over operable component cooling pump in the case of pumps 12 & 13. Waste holdup tanks, monitor tanks, vital cable trays, and service water piping on elevation below.
Safety Injection Pump Monorails	1.3	Auxiliary Building Elevation 84	Safety Injection Pump Motor	2,450	4	Safety injection pump & piping.

TABLE 9.1-4 (Cont)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location (ft)	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/ Components Involved in Dropped Lift
Containment Spray Pump Monorails	2.15	Auxiliary Building Elevation 84	Containment Spray Pump Motor	4,000	3 1/4	Associated containment spray piping. Chemical Volume Control (CVC) System and service water piping and vital cable trays on the elevation below.
Monorail Serving Elevation 55' and Elevation 45'	2.15	Auxiliary Elevation 55	Residual Heat Building Motor	3,950 Removal Pump	2 1/2 above el. 55′	Residual heat removal pump and piping.
			Access Plug	12,400	1 above El. 55′	
Temporary Crane	18*	Roof	Misc.			Safety related equipment on the
Mobile Crane	30**	Auxiliary Building el. 140′				floors below.
Cask Handling Overhead Crane	115 Main 10 Aux	Fuel Handling Building Elevation 130	Spent Fuel Cask w/Spent Fuel	200,000		See Notes 1 & 2 Spent fuel in racks Transfer Pool liner
			Bottom Block	4,200		
Service Water Strainers Monorails	5	Service Water Intake Structure above Service Water Strainer El. 90′	Service Water Strainer	7,000	12	Service water piping and header. Intake bays pump suctions on elevation below.
Mobile Crane	160	Service Water Intake Structure El. 112′	Service Water Concrete Cover Plugs (hatch MKPC-1 and MKPC-2)	12,000 & 13,500	1 Area A	Service Water intake structure Service Water piping and header & intake bay pump suctions on the elevation below see Note 4.
Crawler Crane	275					

Note 1: Because the crane is single failure proof as per ASME NOG-1-2004, a load drop is not credible.

Note 2: The cask handling overhead crane can be load tested for a lower capacity and used to lift lower loads.

Note 3: Deleted.

* Original crane is 18 ton Grove crane.
** Tadano crane

TABLE 9.1-4 (Cont)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location (ft)	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/ Components Involved in Dropped Lift
			Service Water Pump	12,800		
			Service Water Pump Motor	13,200		
Crawler Crane	275	Service Water Intake Structure El. 112 & 122	Traveling Screens	17,325	12	
			Fish Gate	3,000	12 Area A&B 2 Area C	Service Water intake structure - service water piping and header & intake bay pump sections on the elevation below, see Note 4.

Note 4: For Area locations see VTD 315130 Sheet 2 "Nine-Month Response for Control of Heavy Loads for Salem Nuclear Station Units 1 & 2" figure B-10, A20 and A21.

The hypochlorite system piping inside the service water intake structure is designed for Class II (seismic) conditions, but the pipe supports are designed to Class I (seismic) criteria.

The separated redundant service water lines between the service water pumps and the Unit 1 component cooling heat exchangers are not located in open trenches as such, but rather are constructed of reinforced concrete pipe completely buried in the ground. Thus, in effect, they are located in "separate trenches." The principal supply line piping runs are separated by about 13 feet. This separation, in conjunction with the depth at which they have been buried, makes these lines essentially invulnerable to damage from a single postulated event.

The above discussion also applies to the service water piping to the Unit 2 component cooling heat exchangers except for one section of piping running along the west side of the Auxiliary Building. Though not buried, this piping is located within a 4 foot-6 inch thick reinforced concrete pipe tunnel. The redundant supply lines within the tunnel are separated by a 3-foot thick reinforced concrete wall, again precluding coincident failure due to a single event.

Status is displayed and control of each service water pump is available on the main control panel so that an operator can determine if an abnormal number of pumps is operating. In addition, indication of the 14 and 24 pump in "TEST" is displayed on the auxiliary annunciator during performance of surveillance testing. Status and control of all SWS isolation valves and motor-operated header block and tie valves is also available to the operator in the Control Room. The motor-operated valve operators (with the exception of the Turbine Area isolation valves) complete their closing or opening cycle in 1 minute while the containment isolation valves can close in 10 seconds. The Turbine Area isolation motor operated valves have a more rapid operating time of a maximum of 37 seconds.

The rupture of a large pipe or other event causing a high system flow demand will be indicated to the operator by decreasing pump header pressure shown on the main control panel. Low pump header pressure will be alarmed to the main control room. If pump discharge header pressure continues to fall, and outside power is available, a backup service water pump will start automatically.

Each SWIS pump compartment contains a sump whose nominal capacity is 49 cu. Ft. (366 gal.), and each has a sump pump capable of removing over 250 gpm. In the event that a pipe rupture occurs in a watertight pump compartment in the service water intake structure, which is beyond the capacity of the sump pump, high sump level for the affected compartment will be alarmed to the Control Room. The Control Room operator can remotely close the tie valves and header block valves at the intake structure to isolate the affected compartment and remotely start the remaining pumps in the other pump compartment to permit an orderly plant shutdown.

In the event that a main yard supply header is ruptured, the affected header can be isolated by the Control Room operator who can also open the tie valves at the Auxiliary Building. Rupture of a header pipe for Unit 2 in the pipe tunnel can also be detected by high level to the Control Room alarm from the sumps containing a 100 gpm pump. The Control Room operator can determine the affected header by remotely closing the intake tie valves and observing which pump header is affected by low-low pressure. Once the rupture yard header is isolated, the intake tie valves can be opened and all service water pumps made available.

Service water piping in the Auxiliary Building is, for the most part, accessible during operation for inspection by the operators.

Generic Letter (GL) 96-06 was issued by the NRC to notify utilities of safety significant issues that could affect containment integrity and equipment operability during accident conditions. The SW system is designed to withstand the effects of events described in GL 96-06. These GL concerns of thermally induced overpressure, the development of two-phase flow regions, and column separation or voiding leading to the possibility of waterhammer events are addressed by system modifications.

A pressurized tank in each of the two service water headers is installed to serve the containment fan cooler unit (CFCU) loops. The supply lines between the tanks and the SW headers have fast opening valves to allow flow in the event of a LOOP (Loss Of Off-site Power) or LOOP/LOCA. The tanks have a volume of 15,000 gallons each and are pressurized with nitrogen, and discharge into the SW system upon a loss of off-site power. The vessels are sized to contain sufficient water inventory to keep the SW piping full for all postulated operating and single failure conditions. A separate building houses the storage tanks, piping and the storage tank instrumentation and controls.

In the event that radiation is detected at one of the service water outlets from the containment, the condition is alarmed in the Control Room. The final decision to isolate the coils is based on plant conditions, analyses, and indications.

The service water flow through the containment fan cooler units is indicated on the control console.

A temperature detector monitors the fan cooler outlet temperature, which is indicated on the control console; high water temperature could be an indication of inadequate flow.

The service water flow through each Component Cooling Heat Exchanger is normally controlled by means of a cascade control system which simultaneously throttles both the inlet and outlet control valves with a common control air signal. The valves are throttled to maintain component cooling water outlet temperature as the primary parameter, and flow will be limited to a nominal operating value of 10,000 GPM as the secondary parameter. The Service Water flow can be controlled manually in order to establish the desired Component Cooling outlet temperature. The indicating valve control system is mounted on an instrument panel which is located in the Auxiliary Building in the vicinity of the heat exchanger. In addition, a flow transmitter alarms a service water high flow condition on the overhead annunciator in the Control Room.

In certain post-accident alignments, available system pressure will be limited such that the Component Cooling Heat Exchanger original design flow of 10,000 gpm may not be attainable for both heat exchangers. As noted in Table 9.2-1, the currently evaluated design (minimum required) flow has been defined to be 8,000 gpm with 90° F. water. The capability of meeting or exceeding this flow, where required, is demonstrated in detailed system calculations.

Material inspection, fabrication, and quality control conform to ANSI B31.7. Where not possible to comply with ANSI B31.7, the requirements of ASME III-1971, which incorporated ANSI B31.7, were adhered to. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

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

For the original cement lined piping the use of a later code was restricted to inspection and did not involve any requirements from Section III such as material, stress calculations, etc., that would modify our original design. Consequently, other requirements from a later code would not be applicable. Therefore it is believed that the integrity of field welds has not been compromised and that we have complied with our commitment to use ANSI B31.7 whenever possible. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

As part of a reliability improvement program, replacement of portions of the system piping was initiated in 1988 for both Unit 1 and Unit 2. The replacement material selected after an extensive qualification program is a 6% molybdenum Austenitic Stainless Steel, which is furnished to the material requirements of the ASME code Section III, Division 1. However, fabrication, inspection and installation of this piping material is in accordance with ANSI B31.7 and therefore compliance with the commitment to utilize ANSI B31.7 wherever possible has again been maintained. In addition, the weld inspection criteria of later Editions and Addenda of ASME III, as approved by the NRC, can be specified.

In order to provide enhanced accuracy and repeatability for periodic ASME Section XI performance testing, a full flow Service Water Pump surveillance test line was added to the Service Water Intake

Both units CREACS operates simultaneously in pressurized mode during a radiological design bases accident and in full recirculation mode during a toxic gas, hazardous chemical release, or smoke generated inside the control room area. Provisions in the design provide for a single CREACS train to be operated and provide long term occupancy in the CRE during a radiological condition.

The CAACS and CREACS cooling coils are supplied with chilled water from the Chilled Water System located in each unit's mechanical equipment area located at elevation 100 foot of the Auxiliary Building. Each unit's Chilled Water System consists of three 50% capacity package chiller units, two 100% capacity recirculating pumps, condensers cooled by the service water system (SWS), and interconnecting refrigeration, service water and chilled water piping. The Chilled Water System has a side stream demineralizer to maintain water chemistry and a recirculation line from the chilled water pump (1CHE6, 2CHE7) to the chilled water expansion tank (1CHE1, 2CHE8) drain line to prevent stagnant water conditions in the tank. The demineralizer and recirculation line are added as a part of the plant life extension commitments. The Chilled Water System has ample capacity to cool the areas serviced by CAACS and CREACS during normal and emergency operating conditions. During single CREACS train operation, the associated cooling coil is provided with sufficient chilled water with two chillers in service to maintain temperatures inside the CRE below 85°F at outside summer design conditions, except for the Data Logging Rooms, which are maintained below 90°F. The air conditioning equipment is designed to Class I (seismic) criteria and can be energized from the standby ac power supply.

Depending on outside climatic conditions, one or two CAACS fans per unit are normally in operation, the third serving as standby. The CREACS is isolated and in standby during normal operation. The CAACS normally operates with a fixed amount of outside air to maintain a slight positive pressure in the CRE.

The control area ventilation system has four modes of operation. They are as follows:

Normal (Mode 1)

This is the operating mode for CAACS during normal plant operations. In this mode, a mixture of outside air and recirculated air is supplied to the control room areas (relay room, equipment room, and the CRE) to maintain design temperature conditions within limits. Typically, one or two supply fans are operating with the third acting as a backup. The outside makeup (CAA40 & 43 open) and recirculated air is mixed and filtered through roughing filters, cooled (or heated), and supplied to the control room areas. The CRE and control room areas (relay and control equipment rooms) are maintained at a positive pressure. The CREACS is isolated and in standby.

Fire Inside Control Area (Mode 2)

In the event of a fire or smoke generated in the control room, each units CAACS is manually initiated by the operators for once through, 100% outside air operation or purge. In this mode, all of the normal intake (CAA40, 41, 43 & 45) and exhaust dampers (CAA18 & 19) open and return damper (CAA5) closed to allow 100% outside air to be pumped through the control room areas and expelled to the outside, thereby making the control room habitable. A maximum of two CAACS supply fans can be operating in this mode. Roughing filters are used for filtering the outside air. The CREACS is isolated and in standby.

Fire Outside Control Area (Mode 3)

In the event of airborne toxic gas, hazardous chemical releases, or smoke from outside the control room, provisions are made for 100% recirculated air. In this mode, all of the normal intakes (CAA40, 41, 43 & 45), emergency intakes (CAA48, 49, 50 & 51) and exhaust (CAA18 & 19) dampers are closed isolating the ventilation systems from the outside environment. The Unit 1 and 2 CAACS are isolated from the CRE (by closure of CAA14 and CAA20 dampers) and operates in the full recirculation supplying cool air to the relay and equipment rooms, while both unit's CREACS operate to recirculate air to the CRE. A maximum of two CAACS supply fans and one CREACS supply fan per unit can be operating in this mode. Chilled water control valve CH74 open and CH168 is permanently open to supply chilled water to the CAACS and CREACS coils, respectively. Recirculated air to the control room envelope passes through a cooling coil and high efficiency particulate air (HEPA) and charcoal filter banks. This mode is manually initiated by the operators from both control rooms.

Accident Pressurized - Two Filtration Train Alignment (Mode 4)

A mode of operation has been provided in the event of airborne radioactivity and long term occupancy of the control room. In this mode, all of the normal intake (CAA40, 41, 43 & 45), exhaust (CAA18 & 19), and CRE boundary (CAA14 and CAA20) dampers are closed isolating both units CAACS from the outside environment and the CRE. Chilled water control valve CH168 is permanently open. The CAACS operates in Mode 3 with CH74 valve open. An emergency intake from one unit will open and the opposite will remain closed based on which unit initiated the accident signal. Both CREACS filtration trains will start with one fan operating in each unit. If one of the fans fails to start, the standby fan will automatically start.

Auxiliary Building and the containment. This reduces the potential hazard of irradiated particles being transported throughout the building and reduces the loading on the exhaust filters. The HEPA type exhaust filters, in turn, continuously minimize the release of particulate radioactivity to the environment while the standby charcoal filter is available to adsorb gaseous contamination. The design capability of a three-part high level filtration train ensures that all exhausted emissions from the Auxiliary Building and the containment are within the requirements of 10CFR20.

Availability of the Auxiliary Building supply and exhaust ventilation equipment is ensured by connection to the standby ac power supply.

The room coolers located near vital pumping equipment are single capacity units. The total capacity of the room cooler(s) in a given area, in conjunction with the exhaust air flow rate, is designed to limit the area temperature to the design values even if all pumping equipment in the area is operated continuously. In the event that the Safety Injection Pump Room cooler fails concurrent with operation of both SI pumps, temperature in the SI Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 146°F. Similarly, in the event that the 12 (22) Component Cooling Water (CCW) Room Cooler fails concurrent with operation of both CCW pumps in the room, temperatures in the 12 (22) CCW Heat Exchanger and Pump Room may exceed 120°F. Equipment in this area will operate at temperatures to 132°F.

9.4.2.4 Test and Inspections

All components of the Auxiliary Building Ventilation System are subjected to a test and inspection program. This program is similar to that described for the Containment Ventilation System (Section 9.4.4), except the resistance to LOCA pressure and temperature transients is not applicable to the Auxiliary Building equipment.

The Auxiliary Building exhaust air filtration system testing is contained in the Salem Technical Requirements Manual.

9.4.3 Fuel Handling Area Ventilation

9.4.3.1 Design Bases

The Ventilation System is designed to exhaust the spent fuel pool area at 60 air changes an hour within a 10-foot height above the pool during design conditions for spent fuel storage. Out of a system operating capacity of 20,000 cfm, 15,000 cfm is exhausted from the spent fuel pool area (10,000 of which is extracted right at the pool surface) and the remaining 5,000 cfm of system capacity ventilates other parts of the building.

Because of the potential for radioactive releases from the spent fuel, defective fuel cladding or a fuel handling mishap, the building is maintained at a slight negative pressure to assure inleakage of air rather than outleakage.

The total capacity of the Ventilation System, along with the area space heaters, is designed to maintain the building between 60°F and 105°F. The space heaters are not safety-related, do not receive Class 1E power, and would not be available during a loss of offsite power. An evaluation of the Fuel Handling Building has justified a minimum temperature of 40°F. Although there is no direct control of the humidity in the building and there can be instances of 100-percent relative humidity around the spent fuel pool when the outdoor air is damp, the relative humidity under design conditions is expected to be less than 70 percent.

The exhaust filter units, fans and controls are designed to Class I (seismic) criteria. The discharge ductwork from the fuel handling area to the plant vent is also designed to Class I (seismic) criteria. The supply air equipment is served by the Normal AC Power System only, whereas the exhaust air equipment can be energized from the Standby AC Power System in the event of a loss of offsite power. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1.

10.2.2.5 Instrumentation

Instrumentation is provided to continuously monitor and/or alarm such turbine generator parameters as the following:

1. Generator load
2. Shaft vibration at bearings
3. Shaft eccentricity
4. Shell expansion
5. Differential expansion between turbine shell and rotor
6. Turbine speed
7. Turbine casing temperatures
8. Bearing temperatures
9. Hydrogen gas and stator cooling water temperatures
10. Generator frequency
11. Exhaust hood temperature
12. Condenser vacuum
13. Stator winding temperatures
14. Hydrogen pressure and purity
15. Bearing lube oil and hydraulic oil pressure

10.2.2.6 TURBINE OVERSPEED PROTECTION

The information in this section was relocated to the Salem Technical Requirements Manual.

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10.2.3 Turbine Missiles

The subject of turbine missile characteristics, probability of occurrence and protection of essential safety equipment is covered in Section 3.5.

Section 3.5 also deals with characteristics of the turbine discs, blades, and rotors as they relate to the subject of turbine missile formation.

10.2.4 Evaluation

Automatic control actions, alarms and trips are initiated by deviations of system variables from preset values. In every instance automatic control functions are programmed such that appropriate corrective action is taken to protect the RCS as well as the Steam and Power Conversion Systems.

10.2.5 Turbine Generator Test and Inspection

10.2.5.1 Turbine Generator Monitoring

Each turbine generator is equipped with supervisory instrumentation that monitor such variables as pressure, temperatures, flows, speed, vibration, eccentricity, rotor position, casing differential and rotating differential expansion. In the event that abnormal readings are being received, investigations will be made to ascertain the cause of the abnormal readings and, if necessary, the unit will be shut down. Investigations made may consist of nondestructive tests, such as visual, magnetic particle, liquid penetrant, ultrasonic and radiographic, where deemed possible.

Periodic inspections will be made as recommended by the turbine generator manufacturer.

Design flow rate, scfm	30
Design delivery pressure, psig	100

Gas Analyzer

Redundant gas analyzers, one in each Salem Unit and both cross-connected, are provided in accordance with the recommendations of NUREG-0472 to automatically monitor the concentrations of oxygen and hydrogen in the system, in order to indicate when the accumulation of these gases approaches an explosive mixture. Upon indication by alarm that the oxygen level is approaching a hazardous level, provisions must be made to either isolate the component or purge with nitrogen to the GWS. The gas analyzer has suitable connections for sampling when necessary from the following components:

Waste gas to plant vent

Reactor coolant drain tank

Spent resin storage tank

Gas decay tanks (2 points)

CVCS holdup tanks

Boric acid evaporator and gas stripper
Volume control tank

Pressure relief tank

Gas decay tank samples are analyzed continuously to ensure that the oxygen concentration remains less than or equal to 2 percent. Separate feed lines with calibration gases are provided for analyzer calibration purposes. The

high-span calibration gas is nominally 4% oxygen, and low-span calibration gas is nominally 1% oxygen. The balance of the calibration mixtures consists of nitrogen, except for small amounts of hydrogen (between 1% and 2.5%). The gas mixture allows calibration of the analyzer to the profile expected in the sample stream at alarm conditions. Design data for the analyzers are as follows:

Oxygen	By partial pressure measurement 0-5% O_2 Range
Hydrogen	By partial pressure measurement 0-25% H_2 Range
Recorder printout (chart)	Waste Gas Decay Tank: every 3 minutes Sequential sampling (cover gas): each point

All major equipment in the Gaseous Radwaste Disposal System is located outside of the Reactor Containment Building in the Auxiliary Building, Elevation 64 feet and 122 feet.

Piping

Gas piping is mainly carbon steel with stainless steel piping in some sections installed as part of modifications. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance.

Valves exposed to gases are either carbon steel or stainless steel. Isolation valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive wastes if the tanks might be over-pressurized by improper operation or component malfunction.

Codes and Standards

Additional information is presented in Table 11.2-3 for system piping, valves and compressors.

11.3.4 Operating Procedures

The gaseous wastes processed by this system consist primarily of hydrogen stripped from reactor coolant during boron recycle and degassing operations and nitrogen from the various tank cover gases and from the degassing operation. These gases are discharged to the vent header which feeds the suction of the waste gas compressors.

One of the two waste gas compressors will be operating with the other compressor being on standby. The operating compressor maintains a vent header pressure of 0.5 to 4.0 psig. If the vent header pressure rises to 4 psig, the standby compressor automatically energizes. The compressors can be used to: 1) pump gas to the waste decay tanks; 2) transfer gas between tanks; and 3) pump gas directly to the CVCS holdup tanks.

To pump gas to the gas decay tanks, the operator selects two tanks at the auxiliary control panel No. 104: one to receive gas, and one for standby. When the tank in-service is pressurized to 92 psig, flow is automatically switched to the standby tank and an alarm alerts the operator to select a new standby tank. The decay tank being filled is sampled automatically by the gas analyzer and an alarm will alert the operator to a high oxygen content. The tank must then be isolated and the operator is required to direct flow to the standby tank and select a new standby tank.

As the liquid in the CVCS holdup tanks is processed by the boric acid evaporator, gas must be provided as cover gas to replace the processed liquid. The cover gas may be provided from any of the gas decay tanks or from the nitrogen supply. The gas decay tank supplying the returning cover gas is selected manually at the auxiliary control panel No. 104 by opening the appropriate valve in the return line header. To maximize total residence time for gas decay in the system, the last tank filled should be the first tank returned as cover gas. A backup supply of gas to the holdup tanks is provided from the bulk nitrogen header for makeup when return flow is not available from the decay tanks.

Before a gas decay tank is discharged to the plant vent for release to atmosphere, a sample must be taken to determine activity concentration of the gas and total activity inventory in the tank. Total tank activity inventory is determined from the activity concentration and pressure in the tank. To release the gas, the appropriate local manual stop valve is opened to the plant vent and the gas discharge modulating valve is opened at the auxiliary control panel. If the Plant Vent Radiation Monitor detects high activity during release, the modulating valve automatically trips closed. To reopen the valve, the switch must first be reset by returning it to the closed position. The valve can then be repositioned.

The equipment which connects with the vent header system is limited in number. Under normal operating conditions no air is permitted to enter the vent header. During maintenance operations air could enter the boric acid evaporator vent condenser or the waste evaporator vent condenser. During maintenance operations on either of these pieces of equipment, the valve on the equipment discharge line to the vent header is closed. When maintenance operations are completed, and prior to opening the valves, the equipment is filled with nitrogen to purge the air. During discharge, the nitrogen purge is continued. No fluids can get into the vent header.

1. Control Room Area (Channel 2-R1A, 1-R1A) - This channel continuously monitors the Control Room area. This area monitor does not have its own integral flashing beacon and horn since it is located in the Control Room and an alarmed condition is indicated by the annunciator and audible alarm (Unit 2 is provided with LED alarm indication and an adjustable volume horn). This is a non-safety-related unit with a vital power supply.

2. Containment Area (Low Range) (1-R2, 2-R2)

3. Radiochemistry Laboratory (R3)

4. Charging Pump Room (1-R4, 2-R4)

5. Fuel Handling Building (Channels 1-R5 and 2-R5) - These channels continuously monitor the fuel storage areas. A high radiation alarm from either unit will initiate charcoal filtration of the Fuel Handling Building atmosphere. The Fuel Handling Accident in the Fuel Handling Building was analyzed without credit for filtration by the Fuel Handling Building Ventilation System. For Unit 2 the high radiation alarm will automatically start the exhaust fans. In addition to the integral alarm horn and flashing beacon, these units actuate an emergency evacuation horn in the building and radiation alert lights outside of the building. Each unit is on a separate vital power supply.

6. Sampling Room (R6A)

7. In-core Seal Table (1-R7, 2-R7)

8. Fuel Storage Area (1-R9, 2-R9) - These channels continuously monitor the fuel storage areas. A high radiation alarm from either unit will automatically start the exhaust fans (Unit 2 only) and initiate charcoal

filtration of the Fuel Handling Building atmosphere. The Fuel Handling Accident in the Fuel Handling Building was analyzed without credit for charcoal filtration by the Fuel Handling Building Ventilation System. In addition to the integral alarm horn and flashing beacon, these units actuate an emergency evacuation horn in the building and radiation alert lights outside of the building. Each unit is on a separate vital power supply.

9. Containment Personnel and Equipment Hatches (1-R10A, B and 2-R10A, B)

10. Counting Room (R20B)

11. Containment Area (High Range) (1-R44 A and B and 2-R44 A and B) -These channels continuously monitor the containment area and are provided with a special ion chamber detector for extended range capability in a post-accident environment. This is a safety-related unit with a vital power supply.

12. Public Service Control Point (R23)

13. Fuel Handling and Cask Handling Cranes (1-R32 A and B, 2-R32 A and B) - These channels are not connected to the central Radiation Monitoring System and are not provided with integral horns and flashing beacons. A flashing beacon and alarm bell on the cranes are initiated.

14. Mechanical Penetration Area (1-R34 and 2-R34)

15. Condensate Filter Area (1-R40 and 2-R40)

16. (Deleted)

17. (Deleted)

TABLE 11.4-3 (Cont.)

Channel No.	Channel Description	Type of Detector	Range	Control Function/Interlocks
R23	Monitoring Room	GM Tube	10^{-1} -10^{4} mR/hr	---
1-R32A (2)	Fuel Handling Crane Monitor	GM Tube	10^{-1} -10^{4} mR/hr	---
1-R34	Mechanical Penetration Area	GM Tube	10^{-1} -10^{4} mR/hr	---
1-R44A	Containment (High Range)		10^{0} - 10^{7} R/hr	---
1-R44B	Containment (High Range)		10^{0} - 10^{7} R/hr	---

NOTES:
(1) Also performs a safety function
(2) Local monitor only. Not indicated, recorded, or alarmed in the control room.

TABLE 11.4-4 (Cont.)

Channel No.	Channel Description	Type of Detector	Range	Control Functions/Interlocks
2-R34	Mechanical Penetration Area	GM Tube	10^{-1} -10^{6} mR/hr	---
2-R44A	Containment (High Range)	Ion Chamber	10^{0} -10^{7} R/hr	---
2-R44B	Containment (High Range)	Ion Chamber	10^{0} -10^{7} R/hr	---

NOTES:
(1) Also performs a safety function.
(2) Local only - Not connected to RMS monitor in the Control Equipment Room.

SECTION 13

CONDUCT OF OPERATION

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SECTION 13

CONDUCT OF OPERATIONS

13.1 ORGANIZATION STRUCTURE

The original content of this chapter has been modified as allowed by Regulatory Guide 1.181 in conjunction with NEI 98-03, Guidelines for Updating Final Safety Analysis Reports (see UFSAR Appendix 3A).

On August 21, 2000, the operating licenses for the Salem Units 1 & 2, and for the Hope Creek station were transferred from Public Service Electric & Gas (PSE&G) to PSEG Nuclear LLC. PSEG Nuclear LLC, a limited liability company, is a subsidiary of Public Service Enterprise Group (PSEG), an investor-owned company headquartered in the State of New Jersey. PSEG Nuclear LLC is dedicated to the safe, reliable and efficient operation of the nuclear units and assumes full responsibility for meeting all license obligations. The PSE&G corporate organization and its functions and responsibilities are described in Chapter 2 of the Quality Assurance Topical Report NO-AA-10, as revised.

For the Hope Creek project, Bechtel Power Corporation and Bechtel Construction, Inc. designed and constructed the plant. General Electric Company designed, supplied and provided engineering support for the Nuclear Steam Supply System (NSSS) for the Hope Creek project. For the Salem projects, PSE&G and Westinghouse Electric Corporation jointly participated in the design and construction of each unit. PSE&G provided an experienced and trained staff to support preoperational testing, core load and power ascension testing programs of the nuclear units.

The PSEG Nuclear LLC organizational structure and reporting relationships are described in the Quality Assurance Topical Report NO-AA-10. Roles and responsibilities are described in administrative procedures.

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13.1.1.4.4 Radiation Protection

The Radiation Protection Program and organization are described in Section 12.3.

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Table 13.1-1

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RELATIONSHIP WITH PUBLIC SERVICE ENTERPRJSE GROUP
SALEM UFSAR- REV 31 SHEET 1 OF 1 December 5, 2019 F13.1-1

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PSEG NUCLEAR L.L.C. SALEM GENERATING STATION	
NUCLEAR ORGANIZATION	
SALEM UFSAR - REV 31	SHEET 1 OF 1
December 5, 2019	F13.1-2

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

SITE OPERATIONS ORGANIZATION

SALEM UFSAR – REV 31 SHEET 1 OF 1

December 5, 2019 F13.1-3

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PSEG NUCLEAR L.L.C.
SALEM GENERATING STATION

STATION OPERATIONS DEPARTMENT

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SECTION 15

ACCIDENT ANALYSIS

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The TWINKLE code is used to predict the kinetic behavior of a reactor for transients which cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 18.

15.1.9.6 THINC

The THINC code is described in Section 4.4.3.1.

15.1.9.7 PARAGON

PARAGON is a two-dimensional, multi-group transport theory computer code. The nuclear cross-section library used by PARAGON contains cross-section data based on a 70 energy group structure derived from ENDF/B-VI files. PARAGON performs a 2D 70 group flux calculation which couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique and interface current method. PARAGON is capable of modeling all cell types needed for PWR core design application.

PARAGON is further described in Reference 23.

15.1.9.8 NEXUS

The NEXUS methodology is a reparameterization of the PARAGON nuclear data output and a new reconstruction approach within the ANC core simulator code to simplify the use of this code system for design use. The NEXUS methodlogy provides a linkage between PARAGON and ANC, establishing a new code system, while still using PARAGON.

NEXUS is further described in Reference 24.

15.1.10 References for Section 15.1

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11. Obenshain, F. E. and Foderaro, A. H., "Energy from Fission Product Decay," WAPD-P-652, 1955.

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18. Risher, D. H., Jr. and Barry, R. F., "TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979, November 1972.

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23. W. H. Slagle, "Qualification of the Two-Dimensional Transport Code Paragon (WCAP-16045-P-A)," Revision 0, August 2004.

24. W. H. Slagle, "Qualification of the NEXUS Nuclear Data Methodology (WCAP-16045-P-A)," Addendum 1-A Revision 0, August 2007.

TABLE 15.1-2 (Cont)

Reactivity Coefficients

Faults	Computer Codes Utilized	Assumed Moderator Temperature(1) (Δk/°F)	Moderator Density(1) (Δk/gm/cc)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION III					
Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipe which Actuate Emergency Core Cooling	NOTRUMP, SBLOCTA				3479
Inadvertent Loading of a Fuel Assembly into an Improper Position	PHOENIX-P, PARAGON, NEXUS, ANC	—	NA	NA	3216-3563 (4)
Complete Loss of Forced Reactor Coolant Flow	LOFTRAN THINC, FACTRAN	—	0	Upper	3431
Waste Gas Decay Tank Rupture	NA	—	NA	NA	3577
Single RCC Assembly Withdrawal at Full Power	ANC, THINC PHOENIX-P, PARAGON or NEXUS	—	NA	NA	3423
CONDITION IV					
Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the Reactor Coolant System (Loss of Coolant Accident)	SATAN BASH COCO LOCBART	Function of Moderator Density (See Section 15.4.1)		Function of Fuel Temp. (See Section 15.4.1)	3579

TABLE 15.1-2 (Cont)

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed Moderator Temperature(1) (Δk/°F)	Moderator Density(1) (Δk/gm/cc)	Doppler(2)	Initial NSSS Thermal Power Output Assumed (MWt)
CONDITION IV (cont)					
Major Secondary System Pipe Rupture, up to and Including Double-Ended Rupture (Rupture of a Steam Pipe)	LOFTRAN, THINC	Function of Moderator Density (See Section 15.2.13) (Fig. 15.4-50 Unit 1) (Fig. 15.4-48 Unit 2)		Fig. 15.4-49	0 (Subcritical)
Steam Generator Tube Rupture	NA	NA	NA	NA	3577
Single Reactor Coolant Pump Locked Rotor and Reactor Coolant Pump Shaft Break	LOFTRAN THINC, FACTRAN	—	0	Upper	3431
Fuel Handling Accident	NA	NA	NA		3600
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	TWINKLE, FACTRAN PHOENIX-P, PARAGON or NEXUS	-0 pcm/°F BOL -26 pcm/°F EOL	—	Consistent with lower limit shown on Fig 15.1-5	0 and 3479 (7)

NOTES:

(1) Only one is used in an analysis, i.e., either moderator temperature or moderator density coefficient.
(2) Reference Figure 15.1-5 for Doppler power coefficients.
See UFSAR Section 4.5 for the applicable station reload analysis.
(3) Cases are considered at 3 different initial power levels – 100%, 60%, and 10%.
(4) Core power is assumed in the analysis.
(5) Analysis is performed at 102% of an NSSS power of 3423 MWt which is equivalent to 100.6% of 3471 MWt.
(6) No pump heat is assumed in the analysis.
(7) Analysis is performed at 102% of a core power of 3411 MWt which is equivalent to 100.6% of 3459 MWt.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

A. One or More Dropped RCCAs from the Same Group

The LOFTRAN computer code (Reference 4) calculates the transient system response for the evaluation of the dropped RCCA event. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Transient reactor coolant system state points (temperature, pressure, and power) are calculated by LOFTRAN. Nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient analysis and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the THINC code. The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are performed in accordance with the methodology described in Reference 15. Note that the analysis does not take credit for the power-range negative flux rate reactor trip.

B. Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. As discussed in Reference 15, assumptions made in the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

C. Statically Misaligned RCCA

Steady-state power distributions are analyzed using appropriate nuclear physics computer codes. The peaking factors are then used as input to the THINC code to calculate the DNBR. The analysis examines the following cases:

1. With the reactor initially at full power, the worst rod is withdrawn with bank D inserted at the insertion limit,
2. With the reactor initially at full power, the worst rod is dropped with bank D inserted at the insertion limit, and
3. With the reactor initially at full power, the worst rod is dropped with all other rods out.

The analysis assumes this incident to occur at beginning of life since this results in the least-negative value of the moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of the most-negative moderator temperature coefficient to flatten the power distribution. An analysis was performed to confirm that BOL bounds EOL conditions.

15.2.3.2.2 Results

A. One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will reestablish power.

The plant will establish a new equilibrium condition following a dropped rod event in manual rod control. Without control system interaction, a new equilibrium is achieved at a reduced power level and reduced primary temperature.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

B. Dropped RCCA Bank

A dropped RCCA bank results in a negative reactivity insertion greater than 500 pcm. The core is not adversely affected during the insertion period since power is decreasing rapidly. The transient will proceed as described in Part A. However, the return to power will be less due to the greater worth of the entire bank. The power transient for a dropped RCCA bank is symmetric. Following plant stabilization, normal procedures are followed.

15.2.11.4 Conclusions

It has been demonstrated that for an excessive load increase the minimum DNBR during the transient will not be below the limit value.

15.2.12 Accidental Depressurization of The Reactor Coolant System

15.2.12.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety valve. The event results in a rapidly decreasing RCS pressure. The effect of the pressure decrease is a decrease in the neutron flux via the moderator density feedback. The pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor will be tripped by the following RPS signals:

1. Pressurizer low pressure

2. Overtemperature ΔT

15.2.12.2 Method of Analysis

The accidental depressurization transient is analyzed by employing the detailed digital computer code LOFTRAN. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam

generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

In calculating the DNBR, the following conservative assumptions are made:

1. The accident is analyzed using the Revised Thermal Design Procedure. Initial core power, reactor coolant average temperature, and RCS pressure are assumed to be at their nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions are included in the DNBR limit described in Reference 21.

2. A zero moderator coefficient of reactivity conservative for BOL operation in order to provide a conservatively low amount of negative reactivity feedback due to changes in moderator temperature. The spatial effect of void due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

3. A high (absolute value) Doppler coefficient of reactivity such that the resultant amount of positive feedback is conservatively high in order to retard any power decrease due to moderator reactivity feedback.

It should also be noted that in the analysis power peaking factors are kept constant at the design values while, in fact, the core feedback effects would result in considerable flattening of the power distribution. This would significantly increase the calculated DNBR; however, no credit is taken for this effect.

15.2.12.3 <u>Results</u>

Figure 15.2-38 illustrates the nuclear power transient following the accident. Reactor trip on overtemperature ΔT occurs as shown on Figure 15.2-38. The pressure decay transient following the accident is given on Figure 15.2-38. The resulting DNBR never goes below the limit value as shown on Figure 15.2-39.

The Spurious Operation of the SIS at Power is analyzed using the LOFTRAN [4] code. LOFTRAN simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, feedwater system, steam generator, steam generator safety valves, and the effects of the SI system. The code computes pertinent plant variables, including temperatures, pressures and power level.

The following basic assumptions were used to define and evaluate this event:

a. Initial reactor power is at its maximum value (+0.6%). Uncertainties are deducted from the initial RCS temperature and pressure (-5 $^{\circ}$F and -50 psi). Assuming lower values of initial T_{avg} and pressure tends to reduce the time predicted to fill the pressurizer.

b. The SI signal causes the reactor to trip. Core residual decay heat generation is based upon long term operation at the initial power level.

c. Two centrifugal charging pumps and one positive displacement charging pump are in operation, with the miniflow valves open. Full SI flow begins immediately.

d. The pressurizer sprays and heaters operate at their maximum capacity. The pressurizer sprays limit the RCS pressure, permitting a higher SI delivery rate, which fills the pressurizer sooner. The heaters add energy to pressurized fluid, causing it to expand, and thus fill the pressurizer at an increased rate.

e. Either the pressurizer PORV block valves are open, or they are opened by the operators before the pressurizer safety valves open.

f. One of the pressurizer PORVs opens, and relieves water. The PORVs and downstream piping are qualified for this safety-related application [17].

15.2.14.3 Results

Fuel Cladding Integrity (evaluation)

If the SI signal does not trip the reactor and turbine, then nuclear power would decrease as borated water is added to the core. Since steam flow would be maintained, the mismatch between nuclear power and load would cause T_{avg}, pressurizer pressure, and pressurizer water volume to decrease until the low pressurizer pressure reactor trip setpoint is reached. The DNB ratio would increase, due mainly to the decrease in power and T_{avg}, and always remain above its safety limit value. Therefore, this event would not pose a challenge to fuel clad integrity.

Pressure Limits and Escalation into a More Serious Event (accident analysis)

An analysis was performed using the LOFTRAN code. The resulting transient response plots are depicted in Figures 15.2-44 and 15.2-45.

Nuclear power, T_{avg}, pressurizer pressure, and pressurizer water volume decrease, and steam pressure increases, as the result of the reactor and turbine trips demanded by the spurious SI signal. Pressurizer pressure and pressurizer water volume begin to increase as water is added to the RCS by the SIS and the pressurizer sprays and heaters operate. Pressurizer pressure stabilizes as the pressurizer spraying limits the pressurizer pressure to within about 40 psi above its initial value. The action of the pressurizer sprays, in limiting the pressure, allows more SI water to be added to the reactor coolant system, which surges into the pressurizer. It is assumed that the operators open the PORV block valves, if they are closed, before the pressurizer safety valves open. After the pressurizer becomes water-solid, the pressure rapidly increases to the PORV opening setpoint (conservatively assumed to be only 100 psi above the initial pressure, or 2300 psia). Only one of the two PORVs is assumed to open and relieve water.

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4. Burnett, T. W. T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Non-proprietary), April 1984.

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16. Wathey, T.R., "Conditional Extension of Rod Misalignment Technical Specification for Salem Unit 1 and 2," WCAP-14962-P, August, 1997.

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22. Stewart, J. A., "Salem Unit 1 and 2 Feedwater Malfunction Analysis," CN-TA-15-10, VTD 902896, Sheet 037.

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PSEG Nuclear LLC

SALEM NUCLEAR GENERATING STATION

TRANSIENT RESPONSE TO DROPPED
ROD CLUSTER CONTROL ASSEMBLY

Updated FSAR
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Figure 15.2.11 SHEET 1

In the unlikely event of multiple failures which result in continuous withdrawal of a single RCCA, it is not possible, in all cases, to provide assurance of automatic reactor trip such that core safety limits are not violated. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area "covered" by the RCCA.

15.3.5.2 Method of Analysis

Power distributions within the core are calculated by the ANC Code (Reference 10) based on macroscopic cross sections generated by the PHOENIX-P Code (Reference 9), PARAGON Code (Reference 17), or NEXUS code (Reference 18). The peaking factors are then used by THINC to calculate the minimum DNBR for the event. The case of the worst rod withdrawn from Bank D inserted at the insertion limit, with the reactor initially at full power, was analyzed. This incident is assumed to occur at beginning of life, since this results in the minimum value of the moderator density coefficient. This maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.3.5.3 Results

Two cases have been considered as follows:

1. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the failed RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.2.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on

initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNBR from falling below the limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature ΔT trip would be expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the limit value is 5 percent.

2. If the reactor is in automatic control mode, withdrawal of a single RCCA will result in the immobility of other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case 1 described above. For such cases as above, a trip will ultimately ensue, although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the limit value.

15.3.5.4 Conclusions

For the case of one RCCA fully withdrawn with the reactor in the automatic or manual control mode, and initially operating at full power with Bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNBR < the limit value is 5 percent of the total fuel rods in the core.

For both cases discussed, the indicators and alarms mentioned would function to alert the operator to the malfunction before DNB could occur. For Case 2 discussed above, the insertion limit alarms (both low and low-low alarms) would also serve in this regard.

15.3.6 Accidental Release of Waste Gases

15.3.6.1 <u>Situations Considered</u>

Gaseous activity which could be released in the unlikely event of a tank rupture will result in an offsite whole body and inhalation dose well below 10CFR50.67 limits. The main sources of gaseous

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16. WCAP-16676-NP, R.D. Ankney and J.L. Grover, "Analysis Update for the Inadvertent Loading Event," March 2009.

17. W. H. Slagle, "Qualification of the Two-Dimensional Transport Code Paragon (WCAP-16045-P-A)," Revision 0, August 2004.

18. W. H. Slagle, "Qualification of the NEXUS Nuclear Data Methodology (WCAP-16054-P-A)," Addendum 1-A Revision 0, August 2007.

larger than the reactivity calculated for all cases. These results verified conservatism; i.e., underprediction of negative reactivity feedback from power generation.

3. Minimum SIS capability for the injection of borated flow into the RCS is assumed in the analysis. Due to single failure considerations, injection flow is assumed to be delivered by only a single charging pump. [Note that this assumption is taken conservatively and is beyond normal single-failure criteria. It is made in addition to the minimum SIS (minimum safeguards) assumption, despite the calculated RCS pressure shown in Figure 15.4-51A which is below the shutoff head of the IHSI pump after about 20 seconds, the failure of the Feedwater Regulating Valve of the faulted Steam Generator, and the Regulatory Guide 1.183 R0 requirement to assume that a control rod is stuck at its fully withdrawn position.] The modeling of the SIS in LOFTRAN is described in Reference 27.

   A conservatively bounding total time delay is modeled in the analysis to account for the delay between the time that the ESF actuation setpoint is reached and the time that SIS flow is capable of being pumped from the RWST into the RCS cold leg header. The total time delay assumed in the analysis is 22 seconds. This 22 second assumption was selected to conservatively bound the sum of the following time delay components:

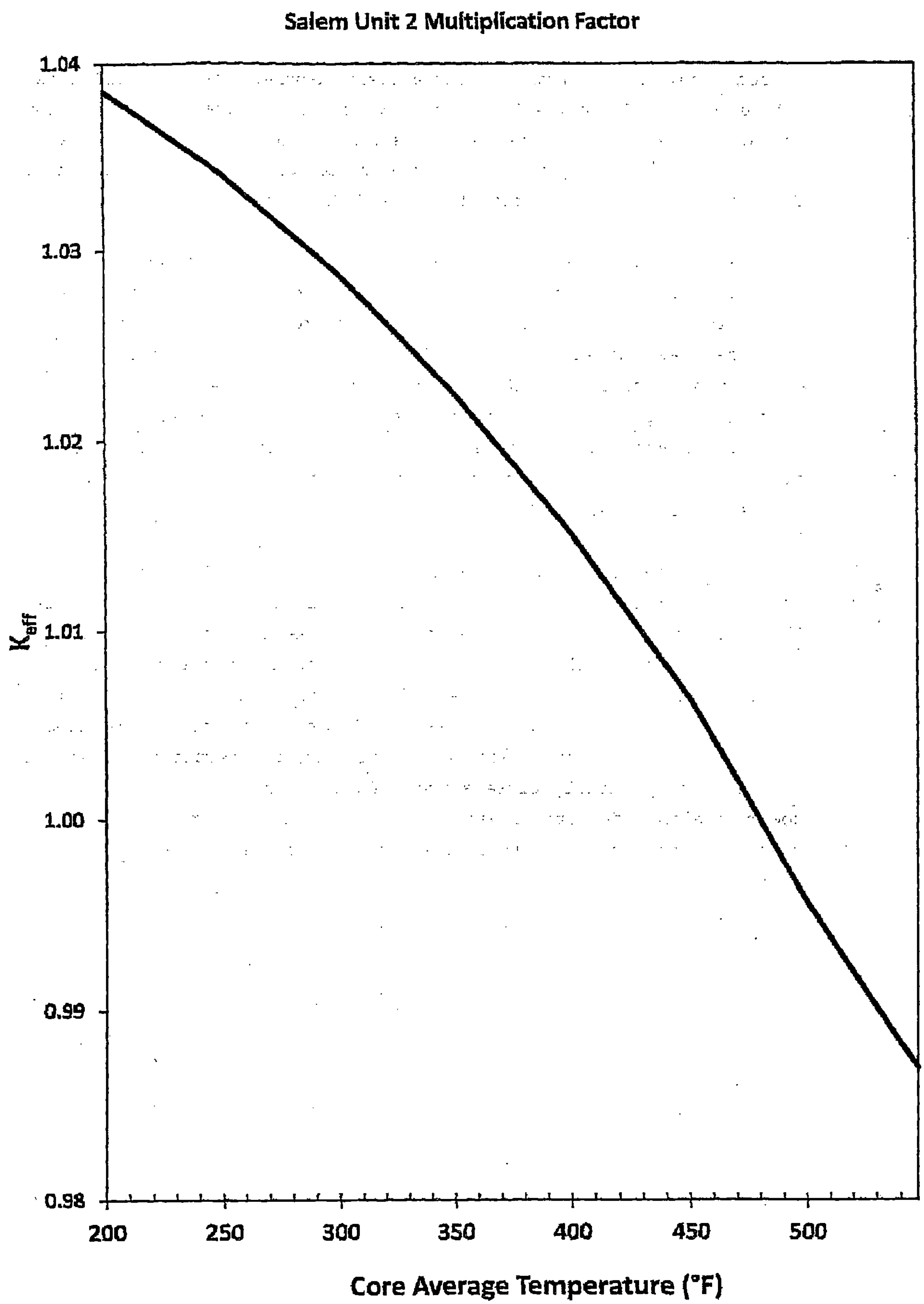
   a. Instrumentation, logic and signal transport time delay associated with generation and transport of the SI signal, and

   b. The following actions which occur in parallel:
      1. SIS suction valve alignment (opening of RWST valves followed by closure of VCT valves), and
      2. High Head SI/Charging Pump starting and attaining full speed.

In addition, the analysis conservatively assumes that the SIS lines between the RWST and the RCS initially contain unborated water. After the appropriate total time delay described above, the analysis takes into account the purging of this unborated water prior to crediting the injection of borated flow from the RWST into the RCS.

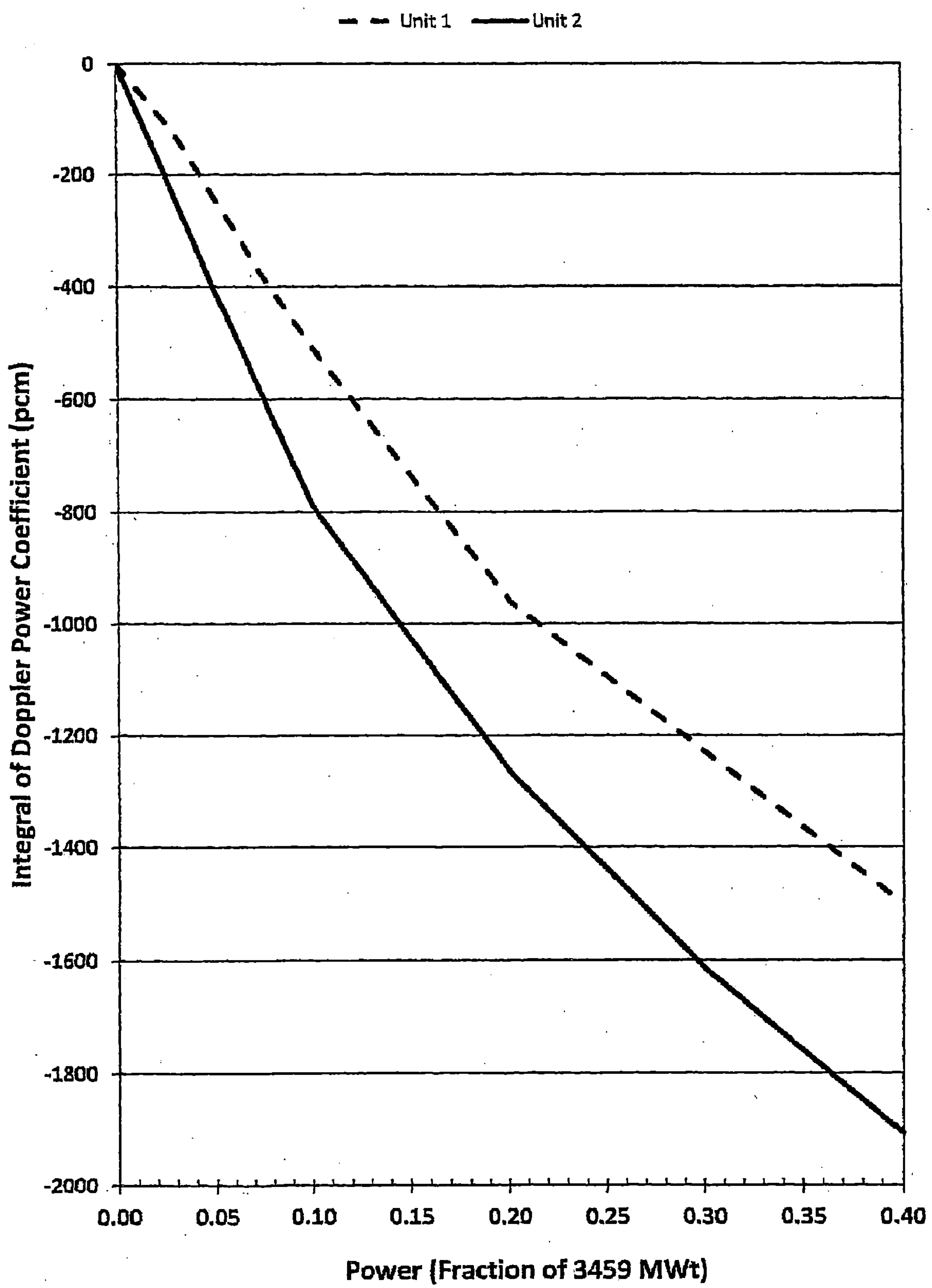
4. Two cases are considered. Both model a complete severance of the main steam line at the outlet of the steam generator with the plant initially at no load conditions. One case models full RCS flow and the other case models loss of RCS flow due to loss of offsite power early in the transient. Note that a loss of offsite power at anytime during the transient results in a loss of forced RCS cooling and subsequently a less severe reactivity transient. As such, the case without offsite power available is not discussed further in this section.

5. Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power phase following the steam line break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow, and, thus, are different for each case studied.



Revision 31 DECEMBER 05,2019

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station VARIATION OF K-eff WITH MODERATOR TEMPERATURE - UNIT 2
	Updated FSAR Figure 15.4-48



Revision 31 DECEMBER 05,2019

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station VARIATION OF REACTIVITY WITH POWER AT CONSTANT CORE AVERAGE TEMPERATURE
	Updated FSAR Figure 15.4-49

7. Add an Examination Checklist for masonry wall inspection requirements.
8. Parameters monitored for wooden components will be enhanced to include: Change in Material Properties, Loss of Material due to Insect Damage and Moisture Damage.
9. Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the service water intake structure.
10. Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license, and a minimum of four years experience working on building structures.
11. Perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of 5 years. Groundwater samples in the areas adjacent to Unit 1 containment structure and Unit 1 auxiliary building will also be tested for boron concentration.
12. Require supplemental inspections of the affected in scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes).
13. Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel.
14. Implementing procedures will be enhanced to include additional acceptance criteria details specified in ACI 349.3R-96.
15. When the reactor cavity is flooded up, Salem will periodically monitor the telltales associated with the reactor cavity and refueling canal for leakage. If telltale leakage is observed, then the pH of the leakage will be measured to ensure that concrete reinforcement steel is not experiencing a corrosive environment. In addition, Salem will periodically inspect the leak chase system associated with the reactor cavity and refueling canal to ensure the telltales are free of significant blockage. Salem will also inspect concrete surfaces for degradation where leakage has been observed, in accordance with this Program.

These enhancements will be implemented prior to entering the period of extended operation.

The following table is provided to tabulate the acceptance criteria from the Structures Monitoring Program Enhancement 5 c. associated with testing the water drained from the Salem Unit 1 SFP telltales and seismic gap drain.

Acceptance Criteria- Salem Unit 1 SFP Telltales and Seismic Gap Drain

Chemical Analysis	Acceptance Criteria		Frequency for monitoring
	SFP Telltales (West Wall)	Seismic Gap Drain (East Wall)	
pH	> 6.0 and < 9.0	> 6.5 and < 10.0	Samples taken monthly
Chloride	≤ 500 ppm	≤ 500 ppm	Samples taken every 6 months
Sulfate	≤ 1,500 ppm	≤ 1,500 ppm	Samples taken every 6 months
Boron	For Information Only	For Information Only	Samples taken monthly
Iron	For Information Only	For Information Only	Samples taken every 6 months

Chemistry results that do not meet one of the criteria will be entered into the corrective action program for an investigation and evaluation.

A.2.1.34 RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants

The RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants is implemented through the Structures Monitoring Program. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is an existing program that will be enhanced to require inspection of water control structures and components that are in scope for license renewal. These structures include the Service Water Intake structure and Shoreline Protection and Dike structures (including outer walls of the Circulating Water Intake Structure). The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect the safety function of the water control structures. The program manages loss of material, cracking, and change in material properties for concrete components, loss of material and loss of preload for steel and metal components, loss of material and change in material properties for wooden components, hardening and loss of strength for elastomers, and loss of material and loss of form for earthen water control structures. Elements of the program are designed to detect degradations and take corrective actions to prevent a loss of an intended function.

The RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program will be enhanced to include: