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Nuclear LLC

MAR 19 2010

10 CFR 50.90

LR-N10-0015
LAR H10-01

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

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

Subject: **APPLICATION FOR TECHNICAL SPECIFICATION CHANGE REGARDING RISK-INFORMED JUSTIFICATION FOR THE RELOCATION OF SPECIFIC SURVEILLANCE FREQUENCY REQUIREMENTS TO A LICENSEE CONTROLLED PROGRAM**

In accordance with the provisions of 10 CFR 50.90 of Title 10 of the Code of Federal Regulations, PSEG Nuclear, LLC (PSEG) requests an amendment to the facility operating license listed above for Hope Creek Generating Station (HCGS).

The proposed amendment would modify HCGS Technical Specifications (TS) by relocating specific surveillance frequencies to a licensee-controlled program, the Surveillance Frequency Control Program, with the implementation of Nuclear Energy Institute (NEI) 04-10, "Risk Informed Method for Control of Surveillance Frequencies."

The changes are consistent with NRC-approved Industry Technical Specifications Task Force Standard Technical Specification Change Traveler, TSTF-425, Revision 3 "Relocate Surveillance Frequencies to Licensee Control - RITSTF Initiative 5b." The availability of this TSTF was announced in the *Federal Register* on July 6, 2009 (74 FR 31996).

Attachment 1 provides a description of the proposed change, the requested confirmation of applicability, and plant-specific verifications. Attachment 2 provides documentation of the Probabilistic Risk Assessment (PRA) technical adequacy. Attachment 3 provides the existing TS pages marked up to show the proposed changes. Attachment 4 provides the existing TS Bases pages marked up to reflect the proposed changes (for information only). Attachment 5 provides the proposed No Significant Hazards Consideration.

There are no regulatory commitments contained in this letter.

PSEG requests approval of the proposed license amendment by March 31, 2011 with implementation within 120 days. The proposed changes have been reviewed by the Plant Operations Review Committee. In accordance with the requirements of 10 CFR 50.91(b)(1), a copy of this application, with attachments, has been sent to the State of New Jersey.

A001
NRR

If you have any questions or require additional information, please contact Mr. Jeffrie Keenan at (856) 339-5429.

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

Executed on 3/10/10
(Date)

Sincerely,

John F. Perry

John F. Perry
Site Vice President
Hope Creek Generating Station

Attachments (5)

S. Collins, Regional Administrator - NRC Region I
R. Ennis, Project Manager - USNRC
NRC Senior Resident Inspector – Hope Creek
P. Mulligan, Manager IV, NJBNE
Commitment Coordinator – Hope Creek
PSEG Commitment Coordinator - Corporate

ATTACHMENT 1
EVALUATION OF THE PROPOSED CHANGE:
LICENSE AMENDMENT TO ADOPT TSTF-425, REVISION 3,
"RELOCATE SURVEILLANCE FREQUENCIES TO LICENSEE CONTROL – RITSTF INITIATIVE 5b"

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1.0 DESCRIPTION

The proposed amendment would modify the Hope Creek Generating Station (HCGS) Technical Specifications (TS) by relocating specific surveillance frequencies to a licensee controlled program with the adoption of Technical Specification Task Force (TSTF) - 425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control - Risk Informed Technical Specification Task Force (RITSTF) Initiative 5b." Additionally, the change would add a new program, the Surveillance Frequency Control Program (SFCP) to TS Section 6, Administrative Controls.

The changes are consistent with NRC-approved Industry/TSTF Standard Technical Specifications (STS) Change Traveler, TSTF-425, Revision 3 (ADAMS Accession No. ML090850642). The Federal Register notice published on July 6, 2009 (74 FR 31996) announced the availability of this TS improvement.

2.0 ASSESSMENT

2.1 Applicability of Published Safety Evaluation

PSEG has reviewed the safety evaluation (SE) dated July 6, 2009. This review included a review of the NRC staff's evaluation, TSTF-425, Revision 3, and the requirements specified in NEI 04-10, Rev. 1 (ADAMS Accession No. ML071360456).

Attachment 2 includes PSEG's documentation with regard to Probabilistic Risk Assessment (PRA) technical adequacy consistent with the requirements of Regulatory Guide 1.200, Revision 1 (ADAMS Accession No. ML070240001), Section 4.2, and describes any PRA models without NRC-endorsed standards, including documentation of the quality characteristics of those models in accordance with Regulatory Guide 1.200.

PSEG has concluded that the justifications presented in the TSTF proposal and the safety evaluation prepared by the NRC staff are applicable to HCGS and justify this amendment to incorporate the changes to the HCGS TS.

2.2 Optional Changes and Variations

The proposed amendment is consistent with STS changes described in TSTF-425, Rev 3. PSEG proposes the following variations or deviations from the NRC approved TSTF, as identified below.

1. Revised (clean) TS pages are not included in the amendment request because of the number of affected pages, the straightforward nature of the proposed changes, and the outstanding license amendment requests affecting the same pages. Providing only the mark ups satisfies the requirements of 10 CFR 50.90 in that the mark ups provide full descriptions of the proposed changes. This deviation from the NRC staff's model application (74 FR 31966) is administrative in nature and does not impact the NRC staff's model safety evaluation published in the same Federal Register Notice. As a result of this deviation, the contents

and numbering of the attachments for this amendment request differ from the attachments specified in the NRC staff's model application. HCGS TS mark ups and bases mark ups are provided in Attachments 3 and 4, respectively.

2. The definition of STAGGERED TEST BASIS is being retained in HCGS TS Definition Section 1.46 since this terminology is mentioned in Administrative TS Section 6.16, "Control Room Envelope Habitability Program," which is not the subject of this amendment request and is not proposed to be changed. This is an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996). Additionally, HCGS TS also has test scheduling strategies for logic trains, channels and other components within systems that are also being relocated, consistent with guidance in NEI 04-10, Rev. 1 (Reference 3)[1]. Similar to a STAGGERED TEST BASIS requirement, these SRs require at least one logic train, channel or component to be tested within one interval and all logic trains, channels or components to be tested within N intervals, where N is the total number of logic trains, channels or components subject to the test requirement. The following SRs contain test scheduling requirements proposed for relocation:
   - SR 4.3.1.3, Reactor Trip System Response Time
   - SR 4.3.2.3, Isolation System Response Time
   - SR 4.3.3.3, ECCS Response Time
   - SR 4.3.11.6, RPS Response Time

   Changes to these scheduling requirements will be controlled under the Surveillance Frequency Control Program (SFCP) which provides the necessary administrative controls for changes to test strategies.

3. Because HCGS has not adopted the NUREG-1433 improved Standard Technical Specifications (ISTS), there are a number of differences between the TSTF Surveillance numbers and HCGS Surveillance numbers. In addition, the Administrative Controls section of TS is Section 6.0 for HCGS versus Section 5.0 for ISTS. These are administrative deviations from TSTF-425 with no impact on the NRC staff's model safety evaluation (74 FR 31996).

   For NUREG-1433 Surveillances that are not contained in HCGS TS, the corresponding NUREG-1433 mark-ups included in TSTF-425 for these Surveillances are not applicable to HCGS. This is also an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation (74 FR 31996).

   For the HCGS plant-specific Surveillances that are not contained in NUREG-1433 and therefore not included in the TSTF-425 mark ups, PSEG has determined that the relocation of the Frequencies for these HCGS plant-specific Surveillances is consistent with TSTF-425, Revision 3, and with the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996), including the scope

[1] Revision 1 to NEI 04-10 is provided to address test strategy (e.g. Staggered Test Basis) in addition to frequency. Under the proposed change, the Frequencies of all Surveillance Requirements (except those that reference other programs for the specific interval or that are event driven) are relocated.

exclusions identified in Section 1.0, "Introduction," of the model safety evaluation. In addition, many of these HCGS plant specific Surveillances are identical to Limerick Generating Station Surveillances that were approved by the NRC for relocation to the SFCP by Amendments 186 and 147 (ADAMS Accession No. ML062420049), Reference 5.

The HCGS plant-specific Surveillances involve fixed periodic frequencies. Changes to the Frequencies for these plant-specific Surveillances would be controlled under the Surveillance Frequency Control Program (SFCP). The SFCP provides the necessary administrative controls to require that Surveillances related to testing, calibration and inspection are conducted at a frequency to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the Limiting Conditions for Operation will be met. Changes to Frequencies in the SFCP would be evaluated using the methodology and probabilistic risk guidelines contained in NEI 04-10, Revision 1, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies," (ADAMS Accession No. ML071360456), as approved by NRC letter dated September 19, 2007 (ADAMS Accession No. ML072570267). The NEI 04-10, Revision 1 methodology includes qualitative considerations, risk analyses, sensitivity studies and bounding analyses, as necessary, and recommended monitoring of the performance of systems, components, and structures (SSCs) for which Frequencies are changed to assure that reduced testing does not adversely impact the SSCs. In addition, the NEI 04-10, Revision 1 methodology satisfies the five key safety principles specified in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998 (ADAMS Accession No. ML003740176) (Ref. 6), relative to changes in Surveillance Frequencies. Therefore, the proposed relocation of the HCGS plant-specific Surveillance Frequencies is consistent with TSTF-425 and with the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration

PSEG has reviewed the proposed no significant hazards consideration (NSHC) determination published in the Federal Register dated July 6, 2009 (74 FR 31996). PSEG has concluded that the proposed NSHC presented in the Federal Register Notice is applicable to HCGS and is provided as Attachment 5 of the submittal, which satisfies the requirements of 10 CFR 50.91(a).

3.2 Applicable Regulatory Requirements

A description of the proposed changes and their relationship to applicable regulatory requirements is provided in TSTF-425, Revision 3 (ADAMS Accession No. ML090850642) and the NRC staff's model safety evaluation published in the Notice of Availability dated July 6, 2009 (74 FR 31996). PSEG has concluded that the relationship of the proposed changes to the applicable regulatory requirements presented in the Federal Register notice is applicable to HCGS.

3.3 Conclusions

In conclusion, based on the considerations above, PSEG has concluded that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

4.0 ENVIRONMENTAL CONSIDERATION

PSEG has reviewed the environmental consideration included in the NRC staff's model safety evaluation published in the Federal Register on July 6, 2009 (74 FR 31996). PSEG has concluded that the staff's findings presented therein are applicable to HCGS and the determination is hereby incorporated by reference for this application.

5.0 REFERENCES

1. TSTF-425, "Relocate Surveillance Frequencies to Licensee Control-RITSTF Initiative 5B," Revision 3.
2. Federal Notice of Availability published on July 6, 2009 (74FR31996)
3. NEI 04-10, Revision 1, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies," April 2007 (ADAMS Accession Number: ML071360456)
4. Regulatory Guide 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," January 2007 (ADAMS Accession Number: ML070240001)
5. NRC Letter to Exelon, "LIMERICK GENERATING STATION, UNITS 1 AND 2- ISSUANCE OF AMENDMENT RE: RELOCATE SURVEILLANCE TEST INTERVALS TO LICENSEE-CONTROLLED PROGRAM (TAC NOS. MC3567 AND MC3568), dated September 28, 2006 (ADAMS Accession No. ML062420049).
6. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998 (ADAMS Accession No. ML003740176)

ATTACHMENT 2

Hope Creek PRA TECHNICAL ADEQUACY Assessment

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Attachment 2 – PRA Technical Adequacy

2.1 Overview

The implementation of the Surveillance Frequency Control Program (also referred to as Tech Spec Initiative 5b) at Hope Creek will follow the guidance provided in NEI 04-10, Revision 1 [Ref. 1] in evaluating proposed surveillance test interval (STI) changes.

The following steps of the risk-informed STI revision process are common to proposed changes to all STIs within the proposed licensee-controlled program.

- Each STI revision is reviewed to determine whether there are any commitments made to the NRC that may prohibit changing the interval. If there are no related commitments, or the commitments may be changed using a commitment change process based on NRC endorsed guidance, then evaluation of the STI revision would proceed. If a commitment exists and the commitment change process does not permit the change, then the STI revision would not be implemented.
- A qualitative analysis is performed for each STI revision that involves several considerations as explained in NEI 04-10 [Ref. 1].
- Each STI revision is reviewed by an Expert Panel, referred to as the Integrated Decision-making Panel (IDP), which is normally the same panel as is used for Maintenance Rule implementation, but with the addition of specialists with experience in surveillance tests and system or component reliability. If the IDP approves the STI revision, the change is implemented and documented for future audits by the NRC. If the IDP does not approve the STI revision, the STI value is left unchanged.
- Performance monitoring is conducted as recommended by the IDP. In some cases, no additional monitoring may be necessary beyond that already conducted under the Maintenance Rule. The performance monitoring helps to confirm that no failure mechanisms related to the revised test interval become important enough to alter the information provided for the justification of the interval changes.
- The IDP is responsible for periodic review of performance monitoring results. If it is determined that the time interval between successive performances of a surveillance test is a factor in the unsatisfactory performances of the surveillance, the IDP returns the STI back to the previously acceptable STI.
- In addition to the above steps, the PRA is used when possible to quantify the effect of a proposed individual STI revision compared to acceptance criteria in Figure 2 of NEI 04-10, Revision 1. Also, the cumulative impact

of all risk-informed STI revisions on all PRAs (i.e., internal events, external events and shutdown) is also compared to the risk acceptance criteria as delineated in NEI 04-10, Revision 1.

For those cases where the STI can not be modeled in the plant PRA (or where a particular PRA model does not exist for a given hazard group), a qualitative or bounding analysis is performed to provide justification for the acceptability of the proposed test interval change.

The NEI 04-10, Revision 1 methodology endorses the guidance provided in Regulatory Guide 1.200, Revision 1 [Ref. 2], "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities." The guidance in RG-1.200 indicates that the following steps should be followed when performing PRA assessments:

1. Identify the parts of the PRA used to support the application
   - SSCs, operational characteristics affected by the application and how these are implemented in the PRA model
   - A definition of the acceptance criteria used for the application
2. Identify the scope of risk contributors addressed by the PRA model
   - If not full scope (i.e. internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Summarize the risk assessment methodology used to assess the risk of the application
   - Include how the PRA model was modified to appropriately model the risk impact of the change request.
4. Demonstrate the Technical Adequacy of the PRA
   - Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
   - Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.
   - Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the Regulatory Guide (currently, RG-1.200

Revision 1 includes only internal events PRA standard). Provide justification to show that where specific requirements in the standard are not adequately met, it will not unduly impact the results.

- Identify key assumptions and approximations relevant to the results used in the decision-making process.

Given the broad scope of potential Initiative 5b applications and the fact that the impact of such assumptions differs from application to application, each of the issues encompassed in Items 1 through 3 will be covered with the preparation of each individual PRA assessment made in support of the individual STI interval requests. The purpose of the remaining portion of this appendix is to address the requirements identified in item 4 above.

2.2 Technical Adequacy of the PRA Model

The HC108B version of the Hope Creek PRA model is the most recent evaluation of the Unit 1 risk profile at Hope Creek for internal event challenges. The Hope Creek PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the Hope Creek PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

PSEG employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all PSEG nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and Hope Creek PRA.

PRA Maintenance and Update

The PSEG risk management process ensures that the applicable PRA model remains an accurate reflection of the as-built and as-operated plants. This process is defined in the PSEG Risk Management program, which consists of a governing procedure (ER-AA-600, "Risk Management") and subordinate implementation procedures. PSEG procedure ER-AA-600-1015, "FPIE PRA Model Update" delineates the responsibilities and guidelines for updating the full power internal events PRA models at PSEG nuclear generation sites. The overall PSEG Risk Management program, including ER-AA-600-1015, defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on CDF is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, PSEG risk management procedures provide the guidance for particular risk management and PRA quality and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for PSEG nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10CFR50.65 (a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 3-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant.

PSEG completed the HC108A update to the Hope Creek PRA model in September 2008, which was the result of a regularly scheduled update of the PRA model. PSEG subsequently completed the HC108B update to the Hope Creek PRA model in November 2008 to incorporate a significant procedural change involving SSW/SACS system operation and to resolve notable comments from the Hope Creek PRA Peer Review performed in October 2008.

As indicated previously, RG-1.200 also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated in to the PRA model, relevant peer review findings, consistency with applicable PRA Standards, and the identification of key assumptions) will be discussed in turn.

2.2.1 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE - PSEG PRA model update tracking database) is created for all issues that are identified that could impact the PRA model. The URE database includes the identification of those plant changes that could impact the PRA model.

As part of the PRA evaluation for each STI change request, a review of open items in the URE database for Hope Creek will be performed and an assessment of the impact on the results of the application will be made prior to presenting the results of the risk analysis to the IDP. If a non-trivial impact is expected, then this may include the performance of additional sensitivity studies or model changes to confirm the impact on the risk analysis.

2.2.2 Applicability of Peer Review Findings and Observations

Several assessments of technical capability have been made, for the Hope Creek Unit 1 PRA model. These assessments are as follows and further discussed in the paragraphs below.

- An independent PRA peer review of the Hope Creek Rev. 0 PRA model (i.e., the Individual Plant Examination (IPE) model) was conducted as a pilot project under the auspices of the BWR Owners' Group in October 1996 following the DRAFT Industry PRA Peer Review process [Ref. 3]. This peer review included an assessment of the PRA model maintenance and update process.

A follow-up independent PRA peer review of the Hope Creek Rev. 1 PRA model was conducted under the auspices of the BWR Owners' Group in November 1999 following the revised Industry PRA Peer Review process [Ref. 4]. This peer review included an assessment of the PRA model maintenance and update process.

- During 2005 and 2006, the Hope Creek PRA model results were evaluated in the BWR Owners' Group PRA cross-comparisons study performed in support of implementation of the mitigating systems performance indicator (MSPI) process.

- A PRA Peer Review of the Hope Creek HC108A PRA was performed during October 2008. The peer review was performed against Addendum B of the ASME PRA Standard [Ref. 5]. The results of the PRA Peer Review indicated that a very small number of the supporting requirements (SRs) were "Not Met" for Capability Category II.

A summary of the disposition of the 1999 Industry PRA Peer Review facts and observations (F&Os) for the Hope Creek PRA models was documented as part of the statement of PRA capability for MSPI in the Hope Creek MSPI Basis Document [Ref. 6]. As noted in that document, there were no open level A or level B F&Os from the 1999 peer review.

2.2.3 Consistency with Applicable PRA Standards

As indicated above, a formal peer review was performed in October 2008 and the final peer review report was issued in March 2009 [Ref. 7]. This peer review was performed against Addendum B of the ASME PRA Standard [Ref. 5], the criteria in RG-1.200, Rev. 1 [Ref. 2] including the NRC positions stated in Appendix A of RG-1.200, Rev. 1 and further issue clarifications [Ref. 8]. The October 2008 peer review identified supporting requirements (SRs) not meeting Capability Category II. Subsequent to the October 2008 peer review, the HC108B PRA model addressed and resolved many of the SRs that did not meet Capability Category II. The SRs that do not meet Capability Category

II for the current HC108B PRA model are summarized in Table 2.2-1 along with an assessment of the impact on the base PRA and their current status.

All remaining gaps will be reviewed for consideration for the next periodic PRA model update, but are judged to have low impact on the PRA model or its ability to support a full range of PRA applications. The remaining gaps are documented in the URE database so that they can be tracked and their potential impacts accounted for in applications where appropriate.

Each item will be reviewed as part of each STI change assessment that is performed and an assessment of the impact on the results of the application will be made prior to presenting the results of the risk analysis to the IDP. If a non-trivial impact is expected, then this may include the performance of additional sensitivity studies or model changes to confirm the impact on the risk analysis.

2.2.4 Identification of Key Assumptions

The overall Initiative 5b process is a risk-informed process with the PRA model results providing one of the inputs to the IDP to determine if an STI change is warranted. The methodology recognizes that a key area of uncertainty for this application is the standby failure rate utilized in the determination of the STI extension impact. Therefore, the methodology requires the performance of selected sensitivity studies on the standby failure rate of the component(s) of interest for the STI assessment.

The results of the standby failure rate sensitivity study plus the results of any additional sensitivity studies identified during the performance of the reviews as outlined in 2.2.1 and 2.2.3 above (including a review of identified sources of uncertainty that were developed for Hope Creek based on the EPRI 1009652 guidance [Ref. 9]) for each STI change assessment will be documented and included in the results of the risk analysis that goes to the IDP.

Table 2.2-1 Gaps to Capability Category II of the ASME PRA Standard			
Applicable SRs	**Description of Gap**	**Related SRs**	**Importance to Application**
DA-D1	Plant specific data was not collected for the most recent update reliability data. The only plant specific information used was for systems that are monitored by the MSPI program. MSPI systems include the diesel generators, HPCI, RCIC, RHR, SSWS and SACS. No other specific data was used for this update. Individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA. FINDING - As outlined in the Component Data Notebook, "individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA." Inadequate data collection and update could have an actual impact on the accuracy of the PRA.		The majority of the high importance systems were updated with recent plant specifc data. The NEI 04-10 methodology requires failure rate sensitivities as part of the analysis which will address this gap.

Table 2.2-1 Gaps to Capability Category II of the ASME PRA Standard			
Applicable SRs	**Description of Gap**	**Related SRs**	**Importance to Application**
QU-E4	Section 3.4 and Appendix B and C of the PRA Summary notebook (HC PSA-013) provide an evaluation of the important model uncertainties and Section 4.5 and Appendix E provide a set of structured sensitivity evaluations based on these uncertainties. Sensitivity calculations were run, with seven cases being identified as important to model uncertainty. Table 4.5-1 of the PSA-013 contains a summary of sensitivity cases to identify risk metric changes associated with candidate modeling uncertainties. The uncertainties are identified based on generic sources of uncertainty provided in EPRI TR-10009652. However, no additional plant-specific sources of uncertainty are addressed. Initial clarification on sources of uncertainty was provided in a July 27, 2007 NRC memorandum, which specified that at a minimum for a base PRA the analyst must "identify the assumptions related to PRA scope and level of detail, and characterize the sources of model uncertainty and related assumptions, i.e., identify what in the PRA model could be impacted and how". In addition, "While an evaluation of any source of model uncertainty or related assumption is not needed for the base PRA, the various sources of model uncertainty and related assumptions do need to be characterized so that they can be addressed in the context of an application. Therefore, the search for candidates needs to be fairly complete (regardless of capability category), because it is not known, a priori, which of the sources of model uncertainty or related assumptions could affect an application." So excluding plant-specific sources of uncertainty from characterization because they did not "rise to the level that they would be considered candidates for modeling uncertainty" is not appropriate. FINDING - The information provided is incomplete; the most recent industry guidance to address modeling uncertainty in order to meet Cat II for these SRs is not met.	IE-D3,AS-C3,SC-C3,SY-C3,HR-I3,DA-E3,IF-F3,LE-F2/G4	The NEI 04-10 methodology requires uncertainty assessments as applicable to the specific analysis. The identified generic uncertainties and assumptions will form a base for this assessment.

Table 2.2-1
Gaps to Capability Category II of the ASME PRA Standard

Applicable SRs	Description of Gap	Related SRs	Importance to Application
SY-A6	System components and boundaries are typically not defined in the system notebooks but referred to the Component Data Notebook. This is acceptable for components but the system boundaries should be defined in the system notebook. FINDING - The information provided is incomplete such that the SR is not met.	SY-A3	This is a documentation issue not affecting the ability to perform Surveillance Test Interval analyses in accordance with the NEI 04-10 methodology.
SY-C2	The documentation present in the system notebooks largely addresses the suggested topics from this SR. However, there are several recommendations for improving the documentation: 1. Section 4.4, Dependency Matrix, should have a legend detailing what A and B represent, this was seen in the CRD notebook. 2. Section 2.10 has generic spatial dependencies for CRD. For CS it states "No spatial dependencies other than those imposed by room cooling, internal flooding, and LOCA harsh environment." No details are provided. No details are provided on room location for the CRD and CS notebooks. 3. System walkdown checklist should be used to address the topics in SY-C2. There are system walkdown checklists for the flooding but the questions and focus is not the same as required in SY-C2. 4. If only going to list the basic events in the Quantification Notebook there should be a tie in each System notebook going to the respective systems. FINDING - The information provided is incomplete such that the SR is not fully met; the information provided must be more readily defensible and traceable. It is noted that both SRs SY-C2 and SY-A14 meet Capability Category II. However, given that F&O SY-C2-01 is categorized as a Finding, these SRs are retained for further evaluation.	SY-A14	This is a documentation issue not affecting the ability to perform Surveillance Test Interval analyses in accordance with the NEI 04-10 methodology.

2.3 External Events Considerations

External hazards were evaluated in the Hope Creek Individual Plant Examination for External Events (IPEEE) submittal in response to the NRC IPEEE Program (Generic Letter 88-20 Supplement 4) [Ref. 10]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

The results of the Hope Creek IPEEE study are documented in the Hope Creek IPEEE [Ref. 11]. Each of the Hope Creek external event evaluations were reviewed as part of the Submittal by the NRC and compared to the requirements of NUREG-1407 [Ref. 12]. The NRC transmitted to PSEG in 1999 their Staff Evaluation Report of the Hope Creek IPEEE Submittal [Ref. 13].

Consistent with Generic Letter 88-20, the Hope Creek IPEEE Submittal does not screen out seismic or fire hazards, but provides quantitative analyses. The seismic risk analysis provided in the Hope Creek Individual Plant Examination for External Events is based on a detailed Seismic Probabilistic Risk Assessment, or Seismic PRA.

The Hope Creek Seismic PRA study is a detailed analysis that, like the internal fire analysis, uses quantification and model elements (e.g., system fault trees, event tree structures, random failure rates, common cause failures, etc.) consistent with those employed in the internal events portion of the Hope Creek IPE study. Hope Creek currently does not maintain a Seismic PRA.

The internal fire events were addressed by using a combination of the Fire Induced Vulnerability Evaluation (FIVE) methodology [Ref. 14] and industry accepted Fire PRA techniques. The Hope Creek Fire PRA study is a detailed analysis that, like the internal fire analysis, uses quantification and model elements (e.g., system fault trees, event tree structures, random failure rates, common cause failures, etc.) consistent with those employed in the internal events portion of the Hope Creek IPE study. Hope Creek currently does not maintain a Fire PRA.

As such, there are no comprehensive CDF and LERF values available from the IPEEE to support the STI risk assessment.

In addition to internal fires and seismic events, the Hope Creek IPEEE analysis of high winds or tornados, external floods, transportation accidents, nearby facility accidents, release of onsite chemicals, detritus and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards.

2.3.1 Discussion of External Events Evaluations

Seismic PRA

The Hope Creek IPEEE Seismic PRA was developed using a process as described in the IPEEE submittal and summarized below:

- Seismic hazard analysis
- Seismic fragility assessment
- Seismic systems analysis
- Quantification of Seismic CDF

Some of the highlights of the Hope Creek Seismic PRA methodology include the following:

- Seismic fragilities based on revised Lawrence Livermore National Laboratory (LLNL) seismic hazard estimates. The EPRI site specific seismic hazard study are used as input as a sensitivity case.
- A seismic event is not assumed to result in a Loss of Offsite Power (LOOP). Seismic failure of offsite power is evaluated on a probabilistic basis according to component fragilities.

The Hope Creek IPEEE states that no plant unique or new vulnerabilities associated with the Seismic Analysis were identified. As identified above, the seismic PRA is not currently maintained for Hope Creek. Thus, quantitative insights can be derived based on the seismic PRA or a qualitative assessment can be performed.

Fire PRA

The Hope Creek IPEEE Fire PRA was developed using a multi-step process as described in the IPEEE submittal and summarized below:

- Step 1 – Fire compartment interaction analysis
- Step 2 – FIVE methodology quantitative screening
- Step 3 -- Develop fire PRA analysis in accordance with NUREG/CR-2300 and NUREG/CR-4840

Some of the highlights of the Hope Creek Fire IPEEE methodology include the following:

- Fire initiation frequencies based on the FIVE methodology.
- High hazard rooms (those that contain a large amount of combustibles) were specifically analyzed.

The Hope Creek IPEEE states that no fire induced vulnerabilities were identified as a result of the analysis. The IPEEE also states that the NRC Fire Risk Scoping Study safety Issues were addressed during the fire analysis and it was found that each of the issues has been adequately addressed at Hope Creek. As identified above, the fire PRA is not currently maintained for Hope Creek. Thus, quantitative insights can be derived based on the IPEEE fire PRA or a qualitative assessment can be performed.

<u>Other External Hazards</u>

The other external hazards are assessed to be non-significant contributors to plant risk:

- High Winds / Tornadoes: The probability of wind speeds exceeding 360 mph is calculated to be 1E-7. This is the design basis tornado wind speed for Hope Creek Generating Station. No issues were identified.
- Transportation and Nearby Facility Hazards: The IPEEE identifies that the frequency of Transportation and Nearby Facility accidents is concluded to be acceptable low. Transportation and nearby

hazards were screened from further consideration in the IPEEE. Additionally, river traffic hazards were evaluated to be acceptably low.

- External Floods: The Hope Creek site has a general grade elevation of 101.5' PSE&G datum. The Probable Maximum Hurricane (PMH) elevation at the site is 35.4' mean sea level (MSL). The plant design complies with the Standard review plan criteria and external floods were screened from further consideration in the IPEEE.

- River Detritus was evaluated in the IPEEE because of plant issues that were resolved with changes to the plant and operating procedures. Detritus induced loss of all service water pumps has been shown to have a frequency that was less than the IPEEE screening criteria.

The NEI 04-10, Revision 1 methodology allows for STI change evaluations to be performed in the absence of quantifiable PRA models for all external hazards. For those cases where the STI cannot be modeled in the plant PRA (or where a particular PRA model does not exist for a given hazard group), a qualitative or bounding analysis is performed to provide justification for the acceptability of the proposed test interval change.

Therefore, in performing the assessments for the other hazard groups, the qualitative or bounding approach will be utilized in most cases.

2.4 Summary

The Hope Creek PRA maintenance and update processes and technical capability evaluations described above provide a robust basis for concluding that the PRA is suitable for use in risk-informed processes such as that proposed for the implementation of a Surveillance Frequency Control Program. As indicated above, in addition to the standard set of sensitivity studies required per the NEI 04-10, Revision 1 methodology, open items for changes at the site and remaining gaps to specific requirements in the PRA standard will be reviewed to determine which, if any, would merit application-specific sensitivity studies in the presentation of the application results.

2.5 References

[1] *Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies, Industry Guidance Document*, NEI 04-10, Revision 1, April 2007.

[2] Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities*, Revision 1, January 2007.

[3] Boiling Water Reactors Owners' Group, *BWROG PSA Peer Review Certification Implementation Guidelines* (DRAFT) July 1996.

[4] Boiling Water Reactors Owners' Group, *BWROG PSA Peer Review Certification Implementation Guidelines*, Revision 3, January 1997.

[5] American Society of Mechanical Engineers, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, (ASME RA-S-2002), Addenda RA-Sa-2003, and Addenda RA-Sb-2005, December 2005.

[6] Hope Creek MSPI Basis Document, Rev. 5, March 2009.

[7] Hope Creek Generating Station PRA Peer Review Report Using ASME PRA Standard Requirements, March 2009.

[8] U.S. Nuclear Regulatory Commission Memorandum to Michael T. Lesar from Farouk Eltawila, "Notice of Clarification to Revision 1 of Regulatory Guide 1.200," July 27, 2007.

[9] Guideline for the Treatment of Uncertainty in Risk-Informed Applications, EPRI TR-1009652, K. Canavan Project Manager, December 2004.

[10] NRC Generic Letter 88-20, *Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10 CFR 50.54(f),* Supplement 4, June 28, 1991.

[11] PSEG, *Hope Creek Generating Station Individual Plant Examination for External Events*, July 1997.

[12] NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities,* June 1991.

[13] NRC Staff Evaluation Report (SER) of Individual Plant Examination for External Events (IPEEE) Submittal for Hope Creek Generating Station, July 1999.

[14] Professional Loss Control, Inc., *Fire-Induced Vulnerability Evaluation (FIVE) Methodology Plant Screening Guide*, EPRI TR-100370, Electric Power Research Institute, April 1992.

ATTACHMENT 3
TECHNICAL SPECIFICATION PAGES WITH PROPOSED CHANGES:
LICENSE AMENDMENT TO ADOPT TSTF-425, REVISION 3,
"RELOCATE SURVEILLANCE FREQUENCIES TO LICENSEE CONTROL"

The following Technical Specifications for HCGS (Facility Operating License NPF-57) are affected by this change request:

3/4 1-2	3/4 3-66	3/4 6-10	3/4 8-9
3/4 1-4	3/4 3-67	3/4 6-13	3/4 8-13
3/4 1-5	3/4 3-74	3/4 6-14	3/4 8-14
3/4 1-7	3/4 3-82	3/4 6-15	3/4 8-20
3/4 1-10	3/4 3-83	3/4 6-16	3/4 8-23
3/4 1-14	3/4 3-87	3/4 6-18	3/4 8-24
3/4 1-19	3/4 3-88	3/4 6-44	3/4 8-25
3/4 1-20	3/4 3-105	3/4 6-45	3/4 8-30
3/4 2-1	3/4 3-108	3/4 6-46	3/4 8-38
3/4 2-3	3/4 3-109	3/4 6-47	3/4 8-40
3/4 2-5	3/4 3-110	3/4 6-49	3/4 8-41
3/4 3-1	3/4 4-2a	3/4 6-51	3/4 8-44
3/4 3-7	3/4 4-4	3/4 6-51a	3/4 9-2
3/4 3-8	3/4 4-5	3/4 6-52	3/4 9-3
3/4 3-10	3/4 4-8	3/4 6-52a	3/4 9-4
3/4 3-28	3/4 4-9	3/4 6-53	3/4 9-5
3/4 3-29	3/4 4-10a	3/4 6-53a	3/4 9-11
3/4 3-30	3/4 4-12	3/4 6-55	3/4 9-12
3/4 3-31	3/4 4-20	3/4 7-2	3/4 9-14
3/4 3-32	3/4 4-21	3/4 7-4	3/4 9-16
3/4 3-39	3/4 4-22	3/4 7-5	3/4 9-17
3/4 3-40	3/4 4-25	3/4 7-6a	3/4 9-18
3/4 3-41	3/4 4-28	3/4 7-7	3/4 10-1
3/4 3-44	3/4 4-29	3/4 7-11	3/4 10-3
3/4 3-46	3/4 5-4	3/4 7-12	3/4 10-4
3/4 3-50	3/4 5-5	3/4 7-19	3/4 10-6
3/4 3-51	3/4 5-7	3/4 7-21	3/4 11-2
3/4 3-55	3/4 5-9	3/4 8-4	3/4 11-17
3/4 3-60	3/4 6-1	3/4 8-5	6-16d
3/4 3-61	3/4 6-6	3/4 8-6	
3/4 3-62	3/4 6-9	3/4 8-8	

INSERT 1

In accordance with the Surveillance Frequency Control Program

INSERT 3

6.8.4.j Surveillance Frequency Control Program
This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

REACTIVITY CONTROL SYSTEMS

3/4.1.2 REACTIVITY ANOMALIES

LIMITING CONDITION FOR OPERATION

3.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall not exceed 1% delta k/k.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the reactivity equivalence difference exceeding 1% delta k/k:

a. Within 12 hours perform an analysis to determine and explain the cause of the reactivity difference; operation may continue if the difference is explained and corrected.

b. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall be verified to be less than or equal to 1% delta k/k:

a. During the first startup following CORE ALTERATIONS, and

b. ~~At least once per 31 effective full power days~~ during POWER OPERATION.

INSERT 1

This page reflects pending changes from LAR H09-06.

ACTION (Continued)

2. Within four hours disarm the associated control rod drive:

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

3. The provisions of Specification 3.0.4 are not applicable.

c. With two or more inoperable control rods not in compliance with banked position withdrawal sequence (BPWS) and not separated by two or more OPERABLE control rods*****:

   1. Within 4 hours, restore compliance with BPWS, or

   2. Within 4 hours, restore control rod(s) to OPERABLE status, or

   3. Within 8 hours, verify control rod drop accident limits are met.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

d. One or more BPWS groups with four or more inoperable control rods*****, within 4 hours, restore control rod(s) to OPERABLE status.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

e. With more than 8 control rods inoperable, be in at least HOT SHUTDOWN within 12 hours.

f. With one scram discharge volume (SDV) vent or drain lines*** with one valve inoperable, isolate the associated line within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.****

g. With one or more SDV vent or drain lines*** with both valves inoperable, isolate the associated line within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.***

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The scram discharge volume drain and vent valves shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by:

a. ~~At least once per 24 hours~~ Verifying each valve to be open,* and

b. ~~At least once per 31 days~~ Cycling each valve through at least one complete cycle of full travel.

4.1.3.1.2 When above the low power setpoint of the RWM, all withdrawn control rods not required to have their directional control valves disarmed

---

*These valves may be closed intermittently for testing under administrative controls.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

*** Separate Action entry is allowed for each SDV vent and drain line.

**** An isolated line may be unisolated under administrative control to allow draining and venting of the SDV.

***** Not applicable when THERMAL POWER is greater than 8.6% RATED THERMAL POWER.

The change to the frequency from 7 to 31 days reflects pending changes under LAR H09-03. Deletion of 4.1.3.4 from Surveillance 4.1.3.1.3 reflects pending changes under LAR H09-06.

electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program, and

b. Within 24 hours when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.3, 4.1.3.5, 4.1.3.6 and 4.1.3.7.

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE ~~at least once per 18 months~~ in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves:

1. Close within 30 seconds after receipt of a signal for control rods to scram, and

2. Open when the scram signal is reset.

This page reflects pending changes to the LCO and Surveillance under LAR H09-06.

LIMITING CONDITION FOR OPERATION

3.1.3.3 No more than 13 OPERABLE control rods shall be "slow," in accordance with Table 3.1.3.3-1, and no more than 2 OPERABLE control rods that are "slow" shall occupy adjacent locations.

----------------------------NOTES----------------------------

1. OPERABLE control rods with scram times not within the limits of this Table are considered "slow."

2. Enter applicable Conditions and Required Actions of LCO 3.1.3.2, "Control Rod Maximum Scram Insertion Times," for control rods with scram times > 7.0 seconds to notch position 05. These control rods are inoperable in accordance with SR 4.1.3.2 and are not considered "slow."

Table 3.1.3.3-1

Position Inserted From Fully Withdrawn	Average Scram Insertion Time[(a)(b)] (Seconds)
45	0.52
39	0.86
25	1.91
05	3.44

(a) Maximum scram time from fully withdrawn position, based on de-energization of scram pilot valve solenoids at time zero.

(b) Scram times as a function of reactor steam dome pressure, when < 800 psig are within established limits.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With more than 13 OPERABLE control rods exceeding any of the above limits or more than 2 OPERABLE control rods that are "slow" occupy adjacent locations, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.3 During single control rod scram time surveillances with the control rod drive pumps isolated from the accumulators:

a. Verify each control rod scram time is within the limits of Table 3.1.3.3-1 with reactor steam dome pressure ≥ 800 psig prior to THERMAL POWER exceeding 40% RATED THERMAL POWER after each reactor shutdown ≥ 120 days.

b. Verify for a representative sample, each tested control rod scram time is within the limits of Table 3.1.3.3-1 with reactor steam dome pressure ≥ 800 psig ~~at least once per 200 days of POWER OPERATION~~ in accordance with the Surveillance Frequency Control Program.

c. Verify each affected control rod scram time is within the limits of Table 3.1.3.3-1 with any reactor steam dome pressure prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect scram time.

d. Verify each affected control rod scram time is within the limits of Table 3.1.3.3-1 with reactor steam dome pressure ≥ 800 psig prior to THERMAL POWER exceeding 40% RATED THERMAL POWER after fuel movement within the affected core cell AND prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

3. With one or more control rod scram accumulators inoperable and reactor pressure < 900 psig,

   a) Immediately upon discovery of charging water header pressure < 940 psig, verify all control rods associated with inoperable accumulators are fully inserted otherwise place the mode switch in the shutdown position**, and

   b) Within one hour insert the associated control rod(s), declare the associated control rod(s) inoperable and disarm the associated control valves either electrically or hydraulically by closing the drive water and exhaust water isolation valves.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5*:

   1. With one or more withdrawn control rods inoperable, upon discovery immediately initiate action to fully insert inoperable withdrawn control rods.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

INSERT 1

a. ~~At least once per 7 days~~ by verifying that the indicated pressure is greater than or equal to 940 psig unless the control rod is inserted and disarmed or scrammed.

* At least the accumulator associated with each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

** Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods.

4.1.3.7 The control rod position indication system shall be determined OPERABLE by verifying: → INSERT 1

a. ~~At least once per 24 hours~~ that the position of each control rod is indicated,

b. That the indicated control rod position changes during the movement of the control rod drive when performing Surveillance Requirement 4.1.3.1.2, and

c. That the control rod position indicator corresponds to the control rod position indicated by the "Full Out" position indicator when performing Surveillance Requirement 4.1.3.6.b.

REACTIVITY CONTROL SYSTEMS

3/4.1 5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system consists of two redundant subsystems and shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, and 2

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With one system subsystem inoperable, restore the subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

2. With both system subsystems inoperable, restore at least one subsystem to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. ~~At least once per 24 hours~~ INSERT 1 by verifying that:

1. The temperature of the sodium pentaborate solution in the storage tank is greater than or equal to 70°F.

2. The available volume of sodium pentaborate solution is within the limits of Figure 3.1.5-1.

3. The heat tracing circuit is OPERABLE by determining the temperature of the pump suction piping to be greater than or equal to 70°F.

SURVEILLANCE REQUIREMENTS (Continued)

INSERT 2

b. ~~At least once per 31 days~~ by:

1. Verifying the continuity of the explosive charge.

2. Determining that the available weight of sodium pentaborate is greater than or equal to 5,776 lbs and the concentration of boron in solution is within the limits of Figure 3.1.5-1 by chemical analysis.*

3. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. Demonstrating that, when tested pursuant to Specification 4.0.5, the minimum flow requirement of 41.2 gpm, per pump, at a pressure of greater than or equal to 1255 psig ~~is met~~ INSERT 2

d. ~~At least once per 18 months~~ by:

1. Initiating one of the standby liquid control system subsystem, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel and verifying that the relief valve does not actuate. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of that batch successfully fired. Both injection subsystems shall be tested ~~in 36 months.~~ INSERT 2

2. **Demonstrating that all heat traced piping between the storage tank and the injection pumps is unblocked and then draining and flushing the piping with demineralized water.

3. Demonstrating that the storage tank heaters are OPERABLE by verifying the expected temperature rise of the sodium pentaborate solution in the storage tank after the heaters are energized.

---

* This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below 70°F.

** This test shall also be performed whenever both heat tracing circuits have been found to be inoperable and may be performed by any series of sequential, overlapping or total flow path steps such that the entire flow path is included.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) shall be less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER and ~~at least once per 24 hours~~ INSERT 1 thereafter. INSERT 1

b. Initially and ~~at least once per 12 hours~~ when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

POWER DISTRIBUTION LIMITS

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER.

ACTION:

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the EOC-RPT inoperable limit specified in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, shall be determined to be equal to or greater than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER and ~~at least once per 24 hours~~ → INSERT 1 thereafter.

→ INSERT 1

b. Initially and ~~at least once per 12 hours~~ when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

POWER DISTRIBUTION LIMITS

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed the limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER and ~~at least once per 24 hours~~ INSERT 2 thereafter.

b. Initially and ~~at least once per 12 hours~~ INSERT 2 when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

3/4.3 INSTRUMENTATION
3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within twelve hours.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.1-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~. INSERT 1

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shall be demonstrated to be within its limit ~~at least once per 18 months~~. INSERT 1 Neutron detectors are exempt from response time testing. For the Reactor Vessel Steam Dome Pressure - High Functional Unit and the Reactor Vessel Water Level - Low, Level 3 Functional Unit, the sensor is eliminated from response time testing for RPS circuits. ~~Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system.~~

4.3.1.4 The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 2 or 3 from OPERATIONAL CONDITION 1 for the Intermediate Range Monitors.

*An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 6 hours or the ACTION required by Table 3.3.1-1 for that Trip Function shall be taken.

**If more channels are inoperable in one trip system than in the other, place the trip system with more inoperable channels in the tripped condition, except when this would cause the Trip Function to occur.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (m)	CHANNEL FUNCTIONAL TEST (m)	CHANNEL CALIBRATION(a) (m)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	~~S~~(b) ~~S~~	~~W~~ ~~W~~	~~R~~ ~~R~~	2 3, 4, 5
b. Inoperative	NA	~~W~~	NA	2, 3, 4, 5
2. Average Power Range Monitor(f):				
a. Neutron Flux - Upscale, Setdown	~~S~~(b) ~~S~~	~~W~~(l) ~~W~~	~~SA~~ ~~SA~~	2 3, 4, 5
b. Flow Biased Simulated Thermal Power-Upscale	~~S~~, ~~D~~(g)	~~Q~~	~~W~~(d) (e), ~~SA~~, ~~R~~(h)	1
c. Fixed Neutron Flux - Upscale	~~S~~	~~Q~~	~~W~~(d), ~~SA~~	1
d. Inoperative	NA	~~Q~~	NA	1, 2, 3, 4, 5
3. Reactor Vessel Steam Dome Pressure - High	~~S~~	~~Q~~(k)	~~R~~	1, 2
4. Reactor Vessel Water Level - Low, Level 3	~~S~~	~~Q~~(k)	~~R~~	1, 2
5. Main Steam Line Isolation Valve - Closure	NA	~~Q~~	~~R~~	1
6. This item intentionally blank				
7. Drywell Pressure - High	~~S~~	~~Q~~(k)	~~R~~	1, 2

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (m)	CHANNEL FUNCTIONAL TEST (m)	CHANNEL CALIBRATION (m)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Float Switch	NA	~~Q~~	~~R~~	1, 2, 5(j)
b. Level Transmitter/Trip Unit	~~S~~	~~Q~~(k)	~~R~~	1, 2, 5(j)
9. Turbine Stop Valve - Closure	NA	~~Q~~	~~R~~	1
10. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	NA	~~Q~~	~~R~~	1
11. Reactor Mode Switch Shutdown Position	NA	~~R~~	NA	1, 2, 3, 4, 5
12. Manual Scram	NA	~~W~~	NA	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

(c) DELETED

(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 24% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.

(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

(f) The LPRMs shall be calibrated ~~at least once per 1000 effective full power hours (EFPH)~~. → INSERT 1

(g) Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing recirculation loop flow (APRM % flow).

(h) This calibration shall consist of verifying the 6 ± 0.6 second simulated thermal power time constant.

(i) This item intentionally blank

(j) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(k) Verify the tripset point of the trip unit ~~at least once per 92 days~~. → INSERT 1

(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

(m) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.2.1-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~ INSERT 1

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shall be demonstrated to be within its limit ~~at least once per 18 months~~ INSERT 1 Radiation detectors are exempt from response time testing. The sensor is eliminated from response time testing for MSIV isolation logic circuits of the following trip functions: Reactor Vessel Water Level - Low Low Low, Level 1; Main Steam Line Pressure - Low; Main Steam Line Flow - High. ~~Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months, where N is the total number of redundant channels in a specific isolation trip system.~~

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION (c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level -				
1) Low Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
2) Low Low Low, Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Reactor Building Exhaust Radiation - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. Manual Initiation	NA	~~Q~~(a)	NA	1, 2, 3
2. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3 and *
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Refueling Floor Exhaust Radiation - High	~~S~~	~~Q~~	~~R~~	1, 2, 3 and *
d. Reactor Building Exhaust Radiation - High	~~S~~	~~Q~~	~~R~~	1, 2, 3 and *
e. Manual Initiation	NA	~~Q~~(a)	NA	1, 2, 3 and *
3. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Main Steam Line Radiation - High, High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Main Steam Line Pressure - Low	~~S~~	~~Q~~	~~R~~	1
d. Main Steam Line Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION (c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
MAIN STEAM LINE ISOLATION (Continued)				
e. Condenser Vacuum - Low	~~S~~	~~Q~~	~~R~~	1, 2**, 3**
f. Main Steam Line Tunnel Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
g. Manual Initiation	NA	~~Q~~(a)	NA	1, 2, 3
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCU Δ Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. RWCU Δ Flow - High, Timer	NA	~~Q~~	~~R~~	1, 2, 3
c. RWCU Area Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
d. RWCU Area Ventilation Δ Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
e. SLCS Initiation	NA	~~Q~~(b)	NA	1, 2
f. Reactor Vessel Water Level - Low Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Manual Initiation	NA	~~Q~~(a)	NA	1, 2, 3
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure (Flow) - High	NA	~~Q~~	~~R~~	1, 2, 3
b. RCIC Steam Line Δ Pressure (Flow) - High, Timer	NA	~~Q~~	~~R~~	1, 2, 3
c. RCIC Steam Supply Pressure - Low	NA	~~Q~~	~~R~~	1, 2, 3
d. RCIC Turbine Exhaust Diaphragm Pressure - High	NA	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	TRIP FUNCTION	CHANNEL CHECK (c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION (c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
	REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION (Continued)				
e.	RCIC Pump Room Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
f.	RCIC Pump Room Ventilation Ducts Δ Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
g.	RCIC Pipe Routing Area Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
h.	RCIC Torus Compartment Temperature -High	NA	~~Q~~	~~R~~	1, 2, 3
i.	Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
j.	Manual Initiation	NA	~~R~~	NA	1, 2, 3
6.	HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a.	HPCI Steam Line Δ Pressure (Flow) - High	NA	~~Q~~	~~R~~	1, 2, 3
b.	HPCI Steam Line Δ Pressure (Flow) - High, Timer	NA	~~Q~~	~~R~~	1, 2, 3
c.	HPCI Steam Supply Pressure - Low	NA	~~Q~~	~~R~~	1, 2, 3
d.	HPCI Turbine Exhaust Diaphragm Pressure - High	NA	~~Q~~	~~R~~	1, 2, 3
e.	HPCI Pump Room Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
f.	HPCI Pump Room Ventilation Ducts Δ Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
g.	HPCI Pipe Routing Area Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION (c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
h. HPCI Torus Compartment Temperature - High	NA	~~Q~~	~~R~~	1, 2, 3
i. Drywell Pressure - High	NA	~~Q~~	~~R~~	1, 2, 3
j. Manual Initiation	NA	~~R~~	NA	1, 2, 3
7. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level - Low, Level 3	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA	~~Q~~	~~R~~	1, 2, 3
c. Manual Initiation	NA	~~Q~~(a)	NA	1, 2, 3

* When handling recently irradiated fuel in the secondary containment and during operations with a potential for draining the reactor vessel.

** When any turbine stop valve is greater than 90% open and/or when the key-locked bypass switch is in the Norm position.

(a) Manual initiation switches shall be tested ~~at least once per 18 months~~ INSERT 2. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST ~~at least once per 92 days~~ INSERT 2 as part of circuitry required to be tested for automatic system isolation.

(b) Each train or logic channel shall be tested at least ~~every other 92 days~~.

(c) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~. INSERT 1

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shall be INSERT 1 demonstrated to be within the limit ~~at least once per 18 months~~. ECCS actuation instrumentation is eliminated from response time testing. ~~Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.~~

TABLE [illegible].3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	~~S~~	~~M~~	~~R~~	1, 2, 3
c. Reactor Vessel Pressure - Low	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
d. Core Spray Pump Discharge Flow - Low (Bypass)	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
e. Core Spray Pump Start Time Delay - Normal Power	NA	~~M~~	~~R~~	1, 2, 3, 4*, 5*
f. Core Spray Pump Start Time Delay - Emergency Power	NA	~~M~~	~~R~~	1, 2, 3, 4*, 5*
g. Manual Initiation	NA	~~R~~	NA	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	~~S~~	~~M~~	~~R~~	1, 2, 3
c. Reactor Vessel Pressure - Low (Permissive)	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
d. LPCI Pump Discharge Flow - Low (Bypass)	~~S~~	~~M~~	~~R~~	1, 2, 3, 4*, 5*
e. LPCI Pump Start Time Delay - Normal Power	NA	~~M~~	~~R~~	1, 2, 3, 4*, 5*
f. Manual Initiation	NA	~~R~~	NA	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#				
a. Reactor Vessel Water Level - Low Low, Level 2	~~S~~	~~M~~	~~R~~	1, 2, 3
b. Drywell Pressure - High	~~S~~	~~M~~	~~R~~	1, 2, 3
c. Condensate Storage Tank Level - Low	~~S~~	~~M~~	~~R~~	1, 2, 3
d. Suppression Pool Water Level - High	~~S~~	~~M~~	~~R~~	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	~~S~~	~~M~~	~~R~~	1, 2, 3
f. HPCI Pump Discharge FLow - Low (Bypass)	~~S~~	~~M~~	~~R~~	1, 2, 3
g. Manual Initiation	NA	~~R~~	NA	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4. AUTOMATIC DEPRESSURIZATION SYSTEM##				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. ADS Timer	NA	~~Q~~	~~R~~	1, 2, 3
d. Core Spray Pump Discharge Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. RHR LPCI Mode Pump Discharge Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. Reactor Vessel Water Level - Low, Level 3	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. ADS Drywell Pressure Bypass Timer	NA	~~Q~~	~~R~~	1, 2, 3
h. ADS Manual Inhibit Switch	NA	~~R~~	NA	1, 2, 3
i. Manual Initiation	NA	~~R~~	NA	1, 2, 3
5. LOSS OF POWER				
a. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	NA	NA	~~R~~	1, 2, 3, 4**, 5**
b. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	~~S~~	~~M~~	~~R~~	1, 2, 3, 4**, 5**

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

* When the system is required to be OPERABLE per Specification 3.5.2.
** Required OPERABLE when ESF equipment is required to be OPERABLE.
# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.
Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, and:

   1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within one hour, or if this action will initiate a pump trip, declare the trip system inoperable.

   2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1. Each ATWS recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.1-1~~ INSERT 1

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~ INSERT 1

TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low Low, Level 2	S	M	R
2. Reactor Vessel Pressure - High	S	M	R

INFORMATION ON THIS PAGE HAS BEEN DELETED.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each end-of-cycle recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.2.1-1~~ → INSERT 1

4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~ → INSERT 1

INSERT 1

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit ~~at least once per 18 months~~. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested ~~at least once per 36 months~~ → INSERT 1

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured ~~at least once per 60 months~~ → INSERT 1

TABLE 4.3.4.2.1-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve-Closure	Q	R
2. Turbine Control Valve-Fast Closure	Q	R

INFORMATION ON THIS PAGE HAS BEEN DELETED.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The reactor core isolation cooling (RCIC) system actuation instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.5-2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each RCIC system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.5.1-1.

4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 18 months~~ INSERT 1

TABLE 4.3.5.1-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNITS	CHANNEL CHECK (b)	CHANNEL FUNCTIONAL TEST (b)	CHANNEL CALIBRATION (b)
a. Reactor Vessel Water Level - Low Low, Level 2	~~S~~	~~Q~~	~~R~~
b. Reactor Vessel Water Level - High, Level 8	~~S~~	~~Q~~	~~R~~
c. Condensate Storage Tank Level - Low	NA	~~Q~~	~~R~~
d. Manual Initiation	NA	~~Q~~(a)	NA

(a) Manual initiation switches shall be tested at least once per 18 months. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 92 days as part of circuitry required to be tested for automatic system actuation.

(b) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the Table.

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (f)	CHANNEL FUNCTIONAL TEST (f)	CHANNEL CALIBRATION(a) (f)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	NA	~~Q~~(c)	~~SA~~	1*
b. Inoperative	NA	~~Q~~(c)	NA	1*
c. Downscale	NA	~~Q~~(c)	~~SA~~	1*
2. APRM				
a. Flow Biased Neutron Flux - Upscale	NA	~~Q~~	~~SA~~	1
b. Inoperative	NA	~~Q~~	NA	1, 2, 5
c. Downscale	NA	~~Q~~	~~SA~~	1
d. Neutron Flux - Upscale, Startup	NA	~~Q~~	~~SA~~	2, 5
3. SOURCE RANGE MONITORS				
a. Detector not full in	NA	~~W~~	NA	2, 5
b. Upscale	NA	~~W~~	~~R~~	2, 5
c. Inoperative	NA	~~W~~	NA	2, 5
d. Downscale	NA	~~W~~	~~R~~	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	NA	~~W~~	NA	2, 5
b. Upscale	NA	~~W~~	~~R~~	2, 5
c. Inoperative	NA	~~W~~	NA	2, 5
d. Downscale	NA	~~W~~	~~R~~	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High (Float Switch)	NA	~~Q~~	~~R~~	1, 2, 5**
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	NA	~~Q~~	~~SA~~	1
b. Inoperative	NA	~~Q~~	NA	1
c. Comparator	NA	~~Q~~	~~SA~~	1
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	~~R~~(e)	NA	3, 4

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTES:

a. Neutron detectors may be excluded from CHANNEL CALIBRATION.

b. DELETED

c. Includes reactor manual control multiplexing system input.

d. DELETED

e. Not required to be performed until 1 hour after reactor mode switch is in the shutdown position.

* With THERMAL POWER ≥ 30% of RATED THERMAL POWER.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

f. Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the Table.

INSTRUMENTATION

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-1 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the conditions and at the frequencies ~~shown in Table 4.3.7.1-1~~.

INSERT 2

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Control Room Ventilation Radiation Monitor	S	Q	R	1, 2, 3, and *
2. Area Monitors				
a. Criticality Monitors				
1) New Fuel Storage Vault	S	Q	R	#
2) Spent Fuel Storage Pool	S	Q	R	##
b. Control Room Direct Radiation Monitor	S	Q	R	At all times
3. Reactor Auxiliaries Cooling Radiation Monitor	S	Q	R	At all times
4. Safety Auxiliaries Cooling Radiation Monitor	S	Q	R	At all times
5. Offgas Pre-treatment Radiation Monitor	S	Q	R	**

INFORMATION ON THIS PAGE HAS BEEN DELETED.

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATION

~~#With fuel in the new fuel storage vault.~~
~~##With fuel in the spent fuel storage pool.~~
~~*When recently irradiated fuel is being handled in the secondary containment and during operations with the potential for draining the reactor vessel.~~
~~**When the offgas treatment system is operating.~~

INFORMATION ON THIS PAGE ~~HAS~~ BEEN DELETED.

INSTRUMENTATION

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system instrumentation and controls shown in Table 3.3.7.4-1 and Table 3.3.7.4-2 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring instrumentation channels less than required by Table 3.3.7.4-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE remote shutdown system controls less than required in Table 3.3.7.4-2, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each of the above required remote shutdown monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.7.4-1~~ specified in the Surveillance Frequency Control Program unless otherwise noted by Table 4.3.7.4-1.

4.3.7.4.2 At least one ~~of each of the above~~ remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) ~~at least once per 18 months~~ INSERT 1

TABLE 4.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)
1. Reactor Vessel Pressure	~~M~~	~~R~~
2. Reactor Vessel Water Level	~~M~~	~~R~~
3. Safety/Relief Valve Position (Energization)	~~M~~	NA
4. Suppression Chamber Water Level	~~M~~	~~R~~
5. Suppression Chamber Water Temperature	~~M~~	~~R~~
6. RHR System Flow	~~M~~	~~R~~
7. Safety Auxiliaries Cooling System Flow	~~M~~	~~R~~
8. Safety Auxiliaries Cooling System Temperature	~~M~~	~~R~~
9. RCIC System Flow	~~M~~	~~R~~
10. RCIC Turbine Speed	~~M~~	~~R~~
11. RCIC Turbine Bearing Oil Pressure Low Indication	~~M~~	~~R~~
12. RCIC High Pressure/Low Pressure Turbine Bearing Temperature High Indication	~~M~~	~~R~~

TABLE 4.3.7.4-1 (Continued)

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)
13. Condensate Storage Tank Level Low-Low Indication	~~M~~	~~R~~
14. Standby Diesel Generator 1AG400 Breaker Indication	~~M~~	NA
15. Standby Diesel Generator 1BG400 Breaker Indication	~~M~~	NA
16. Standby Diesel Generator 1CG400 Breaker Indication	~~M~~	NA
17. Standby Diesel Generator 1DG400 Breaker Indication	~~M~~	NA
18. Switchgear Room Cooler 1AVH401 Status Indication	~~M~~	NA
19 Switchgear Room Cooler 1BVH401 Status Indication	~~M~~	NA
20. Switchgear Room Cooler 1CVH401 Status Indication	~~M~~	NA
21. Switchgear Room Cooler 1DVH401 Status Indication	~~M~~	NA

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the Table.

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT		CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)	APPLICABLE OPERATIONAL CONDITIONS
1.	Reactor Vessel Pressure	~~M~~	~~R~~	1,2,3
2.	Reactor Vessel Water Level	~~M~~	~~R~~	1,2,3
3.	Suppression Chamber Water Level	~~M~~	~~R~~	1,2,3
4.	Suppression Chamber Water Temperature	~~M~~	~~R~~	1,2,3
5.	Suppression Chamber Pressure	~~M~~	~~R~~	1,2,3
6.	Drywell Pressure	~~M~~	~~R~~	1,2,3
7.	Drywell Air Temperature	~~M~~	~~R~~	1,2,3
8.	Deleted			
9.	Safety/Relief Valve Position Indicators	~~M~~	~~R~~	1,2,3
10.	Drywell Atmosphere Post-Accident Radiation Monitor	~~M~~	~~R~~**	1,2,3
11.	North Plant Vent Radiation Monitor#	~~M~~	~~R~~	1,2,3
12.	South Plant Vent Radiation Monitor#	~~M~~	~~R~~	1,2,3
13.	FRVS Vent Radiation Monitor#	~~M~~	~~R~~	1,2,3
14.	Primary Containment Isolation Valve Position Indication	~~M~~	~~R~~	1,2,3

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the Table.

**CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

#High range noble gas monitors.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least the following source range monitor channels shall be OPERABLE:

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

APPLICABILITY: OPERATIONAL CONDITIONS 2*, 3 and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least 3 source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within one hour.

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK ~~at least once per~~

INSERT 2

a) ~~12 hours~~ in CONDITION 2*, and

b) ~~24 hours~~ in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** ~~at least once per 18 months~~ INSERT 1

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~. INSERT 1

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3 cps with the detector fully inserted.

d. The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 2* or 3 from OPERATIONAL CONDITION 1.

*With IRM's on range 2 or below.

**Neutron detectors may be excluded from CHANNEL CALIBRATION.

INSTRUMENTATION

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each feedwater/main turbine trip system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations ~~for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.9.1-1.~~ at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and ~~simulated automatic operation of all~~ channels shall be performed ~~at least once per 18 months~~ INSERT 2

TABLE 4.3.9.1-1

~~FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

TRIP FUNCTIONAL CHECK	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
~~1. Reactor Vessel Water Level-High, Level 8~~	~~S~~	~~M~~	~~R~~	~~1~~

INFORMATION ON THIS PAGE HAS BEEN DELETED.

INSTRUMENTATION

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.10 Two channels of the Main Steam Line Radiation - High, High function for the mechanical vacuum pump trip shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2 with mechanical vacuum pump in service and any main steam line not isolated.

ACTION:

a. With one channel of the Main Steam Line Radiation - High, High function for the mechanical vacuum pump trip inoperable, restore the channel to OPERABLE status within 12 hours. Otherwise, trip the mechanical vacuum pumps, or isolate the main steam lines or be in HOT SHUTDOWN within the next 12 hours.

b. With mechanical vacuum pump trip capability not maintained:

1. Trip the mechanical vacuum pumps within 12 hours; or

2. Isolate the main steam lines within 12 hours; or

3. Be in HOT SHUTDOWN within 12 hours.

c. *When a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into the associated ACTIONS may be delayed for up to 6 hours provided the mechanical vacuum pump trip capability is maintained.*

SURVEILLANCE REQUIREMENTS

4.3.10 Each channel of the Main Steam Line Radiation - High, High function for the mechanical vacuum pump trip shall be demonstrated OPERABLE by:

a. Performance of a CHANNEL CHECK ~~at least once per 12 hours~~; INSERT 1

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 92 days~~; INSERT 1

c. Performance of a CHANNEL CALIBRATION ~~at least once per 18 months~~. INSERT 1
The Allowable Value shall be ≤ 3.6 x normal background; and

d. Performance of a LOGIC SYSTEM FUNCTIONAL TEST, including mechanical vacuum pump trip breaker actuation, ~~at least once per 18 months~~. INSERT 1

LIMITING CONDITION FOR OPERATION

3.3.11 Four channels of the OPRM instrumentation shall be OPERABLE*. Each OPRM channel period based algorithm amplitude trip setpoint (Sp) shall be less than or equal to the Allowable Value as specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER.

ACTIONS

a. With one or more required channels inoperable:
   1. Place the inoperable channels in trip within 30 days, or
   2. Place associated RPS trip system in trip within 30 days, or
   3. Initiate an alternate method to detect and suppress thermal hydraulic instability oscillations within 30 days.

b. With OPRM trip capability not maintained:
   1. Initiate alternate method to detect and suppress thermal hydraulic instability oscillations within 12 hours, and
   2. Restore OPRM trip capability within 120 days.

c. Otherwise, reduce THERMAL POWER to less than 24% RTP within 4 hours.

SURVEILLANCE REQUIREMENTS

4.3.11.1 Perform CHANNEL FUNCTIONAL TEST ~~at least once per 184 days~~. INSERT 1

4.3.11.2 Calibrate the local power range monitor ~~once per 1000 Effective Full Power Hours (EFPH)~~ in accordance with Note f, Table 4.3.1.1-1 of TS 3/4.3.1.

INSERT 1

4.3.11.3 Perform CHANNEL CALIBRATION ~~once per 18 months~~. Neutron detectors are excluded.

INSERT 1

4.3.11.4 Perform LOGIC SYSTEM FUNCTIONAL TEST ~~once per 18 months~~.

4.3.11.5 Verify OPRM is enabled when THERMAL POWER is ≥ 26.1% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow ~~once per 18 months~~. INSERT 1

4.3.11.6 Verify the RPS RESPONSE TIME is within limits. ~~Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system.~~ INSERT 1 Neutron detectors are excluded.

* When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated ACTIONS may be delayed for up to 6 hours, provided the OPRM maintains trip capability.

This page reflects changes proposed to 4.4.1.1.3 in LAR H09-02.

4.4.1.1.1 With one reactor coolant system recirculation loop not in operation ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program verify that:

a. Reactor THERMAL POWER is ≤ 60.86% of RATED THERMAL POWER, and

b. The recirculation flow control system is in the Local Manual mode, and

c. The speed of the operating recirculation pump is less than or equal to 90% of rated pump speed.

4.4.1.1.2 With one reactor coolant system recirculation loop not in operation, within no more than 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 38% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow:

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant, and

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements or Specifications 4.4.1.1.2b and 4.4.1.1.2c do not apply when the loop not in operation is isolated from the reactor pressure vessel.

4.4.1.1.3 Deleted.

REACTOR COOLANT SYSTEM

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS*

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

INSERT 2

a. Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 24% of RATED THERMAL POWER and ~~at least once per 24 hours~~ by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when the recirculation pumps are operating in accordance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established pump speed-loop flow characteristics.
   2. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.
   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established patterns by more than 20%.

INSERT 2

b. During single recirculation loop operation, each of the above required jet pumps in the operating loop shall be demonstrated OPERABLE ~~at least once per 24 hours~~ by verifying that no two of the following conditions occur:

   1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established* pump speed-loop flow characteristics.
   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from single recirculation loop flow measurements.
   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* single recirculation loop pattern by more than 20%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 24% of RATED THERMAL POWER.

*During startup following any refueling outage, baseline data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon conclusion of the baseline data analysis. Single loop baseline data shall be recorded the first time the unit enters single loop operation during an operating cycle.

REACTOR COOLANT SYSTEM

RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated core flow with effective core flow** greater than or equal to 70% of rated core flow.

b. 10% of rated core flow with effective core flow** less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2* during two recirculation loop operation.

ACTION:

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. Declare the recirculation loop of the pump with the slower flow not in operation and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits ~~at least once per 24 hours.~~ INSERT 2

*See Special Test Exception 3.10.4.

**Effective core flow shall be the core flow that would result if both recirculation loop flows were assumed to be at the smaller value of the two loop flows.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be ≤ 30% of full open noise level by performance of a: INSERT 1

a. CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ and a

b. CHANNEL CALIBRATION ~~at least once per 18 months~~ INSERT 1

4.4.2.2 At least 1/2 of the safety relief valve pilot stage assemblies shall be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 18 months~~ INSERT 1 and they shall be rotated such that all 14 safety relief valve pilot stage assemblies are removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 40 months~~ INSERT 1 All safety relief valves will be re-certified to meet a ±1% tolerance prior to returning the valves to service after setpoint testing.

4.4.2.3 The safety relief valve main (mechanical) stage assemblies shall be set pressure tested, reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once every 5 years~~ INSERT 1

SAFETY/RELIEF VALVES LOW-LOW SET FUNCTION

LIMITING CONDITION FOR OPERATION

3.4.2.2 The relief valve function and the low-low set function of the following reactor coolant system safety/relief valves shall be OPERABLE with the following settings:

Valve No.	Low-Low Set Function Setpoint* (psig) ±2% Open	Close
F013H	1017	905
F013P	1047	935

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the relief valve function and/or the low-low set function of one of the above required reactor coolant system safety/relief valves inoperable, restore the inoperable relief valve function and low-low set function to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the relief valve function and/or the low-low set function of both of the above required reactor coolant system safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.2.1 The relief valve function and the low-low set function pressure actuation instrumentation shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~. → INSERT 1

b. CHANNEL CALIBRATION, LOGIC SYSTEM FUNCTIONAL TEST and simulated automatic operation of the entire system (excluding actual valve actuation) ~~at least once per 18 months~~. → INSERT 1

*The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The reactor coolant system leakage detection systems shall be demonstrated OPERABLE by:

a. Drywell atmosphere gaseous radioactivity monitoring system-performance of a CHANNEL CHECK ~~at least once per 12 hours~~, a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ and a CHANNEL CALIBRATION ~~at least once per 18 months~~ INSERT 1

b. The drywell pressure shall be monitored ~~at least once per 12 hours~~ and the drywell temperature shall be monitored ~~at least once per 24 hours~~ INSERT 1

c. Drywell floor and equipment drain sump monitoring system-performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ and a CHANNEL CALIBRATION TEST ~~at least once per 18 months~~ INSERT 1

d. Drywell air coolers condensate flow rate monitoring system-performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ and a CHANNEL CALIBRATION ~~at least once per 18 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the drywell atmospheric gaseous radioactivity ~~at least once per 8 hours~~ INSERT 1 (not a means of quantifying leakage),

b. Monitoring the drywell floor and equipment drain sump flow rate ~~at least once per 8 hours~~ INSERT 1, and

c. Monitoring the drywell air coolers condensate flow rate ~~at least once per 8 hours~~ INSERT 1, and

d. Monitoring the drywell pressure ~~at least once per 8 hours~~ INSERT 1 (not a means of quantifying leakage), and

e. Monitoring the reactor vessel head flange leak detection system ~~at least once per 24 hours~~ INSERT 1 (not a means of quantifying leakage), and

f. Monitoring the drywell temperature ~~at least once per 24 hours~~ INSERT 1 (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. ~~At least once per 18 months~~ INSERT 1,** and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE ~~with alarm setpoints per Table 3.4.3.2-2~~ by performance of a~~:~~ CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

~~a. CHANNEL FUNCTIONAL TEST at least once per 31 days, and~~

~~b. CHANNEL CALIBRATION at least once per 18 months.~~

**P.I.V. leak test extension to the first refueling outage is permissible for each RCS P.I.V. listed in Table 3.4.3.2-1, that is identified in Public Service Electric & Gas Company's letter to the NRC (letter No. NLR-N87047), dated April 3, 1987, as needing a plant outage to test. For this one time test interval, the requirements of Section 4.0.2 are not applicable.

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

	TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	OPERATIONAL CONDITIONS IN WHICH SAMPLE AND ANALYSIS REQUIRED
1.	Gross Beta and Gamma Activity Determination	~~At least once per 72 hours~~ INSERT 1	1, 2, 3
2.	Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	~~At least once per 31 days~~ INSERT 1	1
3.	Radiochemical for $\bar{E}$ Determination	~~At least once per 6 months~~* INSERT 1	1
4.	Isotopic Analysis for Iodine	a) At least once per 4 hours, whenever the specific activity exceeds a limit, as required by ACTION b.	1#, 2#, 3#, 4#
		b) At least one sample, between 2 and 6 hours following the change in THERMAL POWER or off-gas level, as required by ACTION c.	1, 2
5.	Isotopic Analysis of an Off-gas Sample Including Quantitative Measurements for at least Xe-133, Xe-135 and Kr-88	~~At least once per 31 days~~ INSERT 1	1

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

REACTOR COOLANT SYSTEM

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1 (hydrostatic or leak testing), and Figure 3.4.6.1-2 (heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS), and Figure 3.4.6.1-3 (operations with a critical core other than low power PHYSICS TESTS), with:

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

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

c. A maximum temperature change of less than or equal to 20°F in any one hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange metal temperature shall be maintained greater than or equal to 79°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figures 3.4.6.1-1, 3.4.6.1-2, and 3.4.6.1-3 as applicable, ~~at least once per 30 minutes.~~ INSERT 1

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-3 within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and ~~at least once per 30 minutes~~ during system heatup.

INSERT 1

4.4.6.1.3 The reactor vessel material surveillance specimens shall be removed and examined, to determine changes in reactor pressure vessel material properties, as required by 10 CFR 50, Appendix H. The results of these examinations shall be used to update the curves of Figures 3.4.6.1-1, 3.4.6.1-2, and 3.4.6.1-3.

4.4.6.1.4 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to the limit specified in 3.4.6.1.d.

a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

   1. ≤ 110°F, ~~at least once per 12 hours~~ INSERT 1
   2. ≤ 90°F, ~~at least once per 30 minutes.~~ INSERT 1

INSERT 1

b. Within 30 minutes prior to and ~~at least once per 30 minutes~~ during tensioning of the reactor vessel head bolting studs.

REACTOR COOLANT SYSTEM

REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1020 psig.

APPLICABILITY: OPERATIONAL CONDITION 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1020 psig, reduce the pressure to less than 1020 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1020 psig ~~at least once per 12 hours.~~ INSERT 1

*Not applicable during anticipated transients.

REACTOR COOLANT SYSTEM

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,##, with each loop consisting of:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.**

b. With no RHR shutdown cooling mode loop or recirculation pump in operation, immediately initiate corrective action to return at least one loop to operation as soon as possible. Within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system, one recirculation pump, or alternate method shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ INSERT 2

One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation or at least one recirculation pump is in operation.

* The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

The RHR shutdown cooling mode loop may be removed from operation during hydrostatic testing.

** Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4 and heat losses to ambient** are not sufficient to maintain OPERATIONAL CONDITION 4.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop or recirculation pump in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system, recirculation pump or alternate method shall ~~be determined~~ to be in operation and circulating reactor coolant ~~at least once per 12 hours~~. INSERT 1

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation or at least one recirculation pump is in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The shutdown cooling mode loop may be removed from operation during hydrostatic testing.

**Ambient losses must be such that no increase in reactor vessel water temperature will occur (even though COLD SHUTDOWN conditions are being maintained).

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. ~~At least once per 31 days:~~ INSERT 1

1. For the core spray system, the LPCI system, and the HPCI system:

   a) Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

   b) Verifying that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.

   c) Verify the RHR System cross tie valves on the discharge side of the pumps are closed and power, if any, is removed from the valve operators.

2. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. The two core spray system pumps in each subsystem together develop a flow of at least 6150 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥105 psi above suppression pool pressure..

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥20 psid.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of 1000 psig when steam is being supplied to the turbine at 1000, +20, -80 psig.**

c. ~~At least once per 18 months:~~ INSERT 1

1. For the core spray system, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

*Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

**The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥200 psig, when steam is being supplied to the turbine at 200 + 15, -0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber - water level high signal.

3. Performing a CHANNEL CALIBRATION of the CSS, and LPCI system discharge line "keep filled" alarm instrumentation.

4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid.

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 1.0 psid.

d. For the ADS:

INSERT 1

1. ~~At least once per 31 days~~ performing a CHANNEL FUNCTIONAL TEST of the Primary Containment Instrument Gas System low-low pressure alarm system.

INSERT 2

2. ~~At least once per 18 months:~~

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5, that each ADS valve is capable of being opened.

   c) Performing a CHANNEL CALIBRATION of the Primary Containment Instrument Gas System low-low pressure alarm system and verifying an alarm setpoint of 85 ±2 psig on decreasing pressure.

**The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

SURVEILLANCE REQUIREMENTS

4.5.2.1 At least the above required ECCS shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1.

INSERT 1

4.5.2.2 The core spray system shall be determine OPERABLE ~~at least once per 12 hours~~ by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2.a.2.b.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying the water level to be greater than or equal to:

a. 74.5" ~~at least once per 24 hours~~ INSERT 1 in OPERATIONAL CONDITIONS 1, 2, and 3.

b. 5.0" ~~at least once per 12 hours~~ INSERT 1 in OPERATIONAL CONDITIONS 4 and 5*.

4.5.3.2 With the suppression chamber level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, ~~at least once per 12 hours~~ INSERT 1

a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

b. Verify footnote conditions * to be satisfied.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing in accordance with the Primary Containment Leakage Rate Testing Program.

INSERT 1

b. ~~At least once per 31 days~~ by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

*See Special Test Exception 3.10.1

**Except valves, blind flanges, and deactivated automatic valves which are located inside the primary containment, and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed when the primary containment has not been de-inerted since the last verification or more often than once per 92 days.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

a. By verifying seal leakage rate in accordance with the Primary Containment Leakage Rate Testing Program.

b. By conducting an overall air lock leakage test in accordance with the Primary Containment Leakage Rate Testing Program.

c. INSERT 2 ~~At least once per 6 months~~ by verifying that only one door in each air lock can be opened at a time.**

**Except that the inner door need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the inner door interlock is tested within 8 hours after the primary containment has been de-inerted.

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -0.5 and +1.5 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell and/or suppression chamber internal pressure outside of the specified limits, restore the internal pressure to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits ~~at least once per 12 hours.~~ INSERT 1

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 135°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell average air temperature greater than 135°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the volumetric average of the temperatures at the following locations and shall be determined to be within the limit ~~at least once per 24 hours~~. INSERT 2

	Elevation Zone	Approximate Azimuth*
a.	86'11"-112'8" (under vessel)	90°, 225°, 90°, 270°
b.	86'11"-111'10" (outside of pedestal)	135°, 300°, 100°, 190°
c.	111'10"-139'2"	55°, 240°, 155°, 315°
d.	139'2"-168'0"	45°, 215°, 0°, 90°, 180°, 270°
e.	168'0"-192'7"	95°, 130°, 300°, 355°, 45°, 225°

*At least one reading from each elevation zone is required for a volumetric average calculation.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

c. With one drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits ~~at least once per 24 hours~~ INSERT 1

INSERT 1 b. ~~At least once per 24 hours~~ in OPERATIONAL CONDITION 1 or 2 by verifying the suppression chamber average water temperature to be less than or equal to 95°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per hour when suppression chamber average water temperature is greater than 95°F, by verifying:

   a) Suppression chamber average water temperature to be less than or equal to 110°F.

c. At least once per 30 minutes in OPERATIONAL CONDITION 3 following a scram with suppression chamber average water temperature greater than 95°F, by verifying suppression chamber average water temperature less than or equal to 120°F.

d. By an external visual examination of the suppression chamber after safety/relief valve operation with the suppression chamber average water temperature greater than or equal to 177°F and reactor coolant system pressure greater than 100 psig.

INSERT 1 e. ~~At least once per 18 months~~ by a visual inspection of the accessible interior and exterior of the suppression chamber.

LIMITING CONDITION FOR OPERATION (Continued)

INSERT 1

f. ~~At least once per 18 months~~ by conducting a drywell-to-suppression chamber bypass leak test at an initial differential pressure of 0.80 psi and verifying that the differential pressure does not decrease by more than 0.24 inch of water per minute for a period of 10 minutes. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the ~~18 month test~~ schedule may be resumed.

Surveillance Frequency Control Program

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger and the suppression pool spray sparger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool spray loop inoperable, restore the inoperable loop to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system shall be demonstrated OPERABLE:

INSERT 2

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

b. By verifying that each of the required RHR pumps develops a flow of at least 540 gpm on recirculation flow through the RHR heat exchanger (after consideration of flow through the closed bypass valve) and suppression pool spray sparger when tested pursuant to Specification 4.0.5.

*Whenever both RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

CONTAINMENT SYSTEMS

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE: INSERT 1

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

b. By verifying that each of the required RHR pumps develops a flow of at least 10,160 gpm on recirculation flow through the RHR heat exchanger (after consideration of flow through the closed bypass valve) and the suppression pool when tested pursuant to Specification 4.0.5.

*Whenever both RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

CONTAINMENT SYSTEMS

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each primary containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

INSERT 2

4.6.3.2 Each primary containment automatic isolation valve shall be demonstrated OPERABLE ~~at least once per 18 months~~ by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.3.3 The isolation time of each primary containment power operated or automatic valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

INSERT 1

4.6.3.4 ~~At least once per 18 months~~ verify that a representative sample of reactor instrumentation line excess flow check valves# actuates to the isolation position on a simulated instrument line break signal.

4.6.3.5 Each traversing in-core probe system explosive isolation valve shall be demonstrated OPERABLE*:

INSERT 2

a. ~~At least once per 31 days~~ by verifying the continuity of the explosive charge.

INSERT 1

b. ~~At least once per 18 months~~ by removing the explosive squib from at least one explosive valve ~~such that each explosive squib in each explosive valve will be tested at least once per 90 months~~, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life or operating life, as applicable.

* Exemption to Appendix J of 10 CFR Part 50.

The reactor vessel head seal leak detection line (penetration J5C) is not required to be tested pursuant to this requirement.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed ~~at least once per 14 days~~* INSERT 1 .

b. Demonstrated OPERABLE:

1. ~~At least once per 31 days~~ INSERT 1 and within 12 hours after any discharge of steam to the suppression chamber from the safety-relief valves, by performing a functional test of each vacuum breaker.

2. ~~At least once per 18 months~~ INSERT 1 by verifying the opening setpoint of each vacuum breaker to be less than or equal to 0.20 psid.

*Not required to be met for vacuum breaker assembly valves that are open during surveillances or that are open when performing their intended functions.

REACTOR BUILDING - SUPPRESSION CHAMBER VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.4.2 Each reactor building - suppression chamber vacuum breaker assembly shall be OPERABLE

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one reactor building - suppression chamber vacuum breaker assembly, with one or two valves inoperable for opening, restore the vacuum breaker assembly to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With two reactor building - suppression chamber vacuum breaker assemblies with one or two valves inoperable for opening, restore both valves in one vacuum breaker assembly to OPERABLE status within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one or two reactor building - suppression chamber vacuum breaker assemblies, with one valve not closed, close the open vacuum breaker assembly valve(s) within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With two valves in one or two reactor building - suppression chamber vacuum breaker assemblies not closed, close one open vacuum breaker assembly valve in each affected assembly within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.4.2 Each reactor building - suppression chamber vacuum breaker assembly shall be:

INSERT 2

a. Verified closed ~~at least once per 14 days~~.

b. Demonstrated OPERABLE: INSERT I

1. ~~At least once per 31 days~~ by:

a) Performing a functional test of each vacuum breaker assembly valve.

SURVEILLANCE REQUIREMENTS (Continued)

2. ~~At least once per 18 months~~ by: INSERT 1

a) Verifying the opening setpoint of each vacuum breaker assembly valve to be less than or equal to 0.25 psid.

*Not required to be met for vacuum breaker assembly valves that are open during surveillances or that are open when performing their intended functions.

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and *.

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2 or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Operational Condition *, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying ~~at least once per 24 hours~~ that the reactor building is at a negative pressure. INSERT 1

b. Verifying ~~at least once per 31 days~~ that: INSERT 1

1. All secondary containment equipment hatches and blowout panels are closed and sealed.

2. a. For double door arrangements, at least one door in each access to the secondary containment is closed.

   b. For single door arrangements, the door in each access to the secondary containment is closed except for routine entry and exit.

3. All secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic dampers/valves secured in position.

c. ~~At least once per 18 months~~ INSERT 1

1. Verifying that four filtration recirculation and ventilation system (FRVS) recirculation units and one ventilation unit of the filtration recirculation and ventilation system will draw down the secondary containment to greater than or equal to 0.25 inches of vacuum water gauge in less than or equal to 375 seconds, and

*When recently irradiated fuel is being handled in the secondary containment and during operations with a potential for draining the reactor vessel.

CONTAINMENT SYSTEMS

SECONDARY CONTAINMENT AUTOMATIC ISOLATION DAMPERS

LIMITING CONDITION FOR OPERATION

3.6.5.2 The secondary containment ventilation system (RBVS) automatic isolation dampers shown in Table 3.6.5.2-1 shall be OPERABLE with isolation times less than or equal to the times shown in Table 3.6.5.2-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and *.

ACTION:

With one or more of the secondary containment ventilation system automatic isolation dampers shown in Table 3.6.5.2-1 inoperable, maintain at least one isolation damper OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable dampers to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated damper secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve or blind flange.

Otherwise, in OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

Otherwise, in Operational Condition *, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.2 Each secondary containment ventilation system automatic isolation damper shown in Table 3.6.5.2-1 shall be demonstrated OPERABLE:

a. Prior to returning the damper to service after maintenance, repair or replacement work is performed on the damper or its associated actuator, control or power circuit by cycling the damper through at least one complete cycle of full travel and verifying the specified isolation time.

→ INSERT 2

b. ~~At least once per 18 months~~ by verifying that on a containment isolation test signal each isolation damper actuates to its isolation position.

c. By verifying the isolation time to be within its limit ~~at least once per 92 days~~ → INSERT 1

* When recently irradiated fuel is being handled in the secondary containment and during operations with a potential for draining the reactor vessel.

CONTAINMENT SYSTEMS

3.6.5.3 FILTRATION, RECIRCULATION AND VENTILATION SYSTEM (FRVS) FRVS VENTILATION SUBSYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3.1 Two FRVS ventilation units shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and *.

ACTION:

a. With one of the above required FRVS ventilation units inoperable, restore the inoperable unit to OPERABLE status within 7 days, or:

   1. In OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   2. In Operational Condition *, place the OPERABLE FRVS ventilation unit in operation or suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

b. With both ventilation units inoperable in Operational Condition *, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3.1 Each of the two ventilation units shall be demonstrated OPERABLE:

INSERT 1

a. ~~At least once per 14 days~~ by verifying that the water seal bucket traps have a water seal and making up any evaporative losses by filling the traps to the overflow.

INSERT 1

b. ~~At least once per 31 days~~ by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 15 minutes.

*When recently irradiated fuel is being handled in the secondary containment and during operations with a potential for draining the reactor vessel.

SURVEILLANCE REQUIREMENTS (Continued) INSERT 2

c. ~~At least once per 18 months~~ or upon determination** that the HEPA filters or charcoal adsorbent could have been damaged by structural maintenance or adversely affected by any chemicals, fumes or foreign materials (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rates are 9,000 cfm ± 10% for each FRVS ventilation unit.

2. Verifying within 31 days after removal from the FRVS ventilation units, that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration less than 5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity 95%.

3. Verifying a subsystem flow rate of 9,000 cfm ± 10% for each FRVS ventilation unit during system operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal from the FRVS ventilation units, that a laboratory analysis of a representative carbon sample, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows a methyl iodide penetration less than 5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

**This determination shall consider the maintenance performed and/or the type, quantity, length of contact time, known effects and previous accumulation history for all contaminants which could reduce the system performance to less than that verified by the acceptance criteria in items c.1 through c.3 below.

SURVEILLANCE REQUIREMENTS (Continued)

e. ~~At least once per 18 months~~ by: INSERT 2

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5 inches Water Gauge in the ventilation unit while operating the filter train at a flow rate of 9,000 cfm ± 10% for each FRVS ventilation unit.

2. Verifying that the filter train starts and isolation dampers open on each of the following test signals:

   a. Manual initiation from the control room, and

   b. Simulated automatic initiation signal.

f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration testing acceptance criteria of less than 0.05% in accordance with Regulatory Position C.5.a and C.5.c of Regulatory Guide 1.52, Revision 2 March 1978, while operating the system at a flow rate of 9,000 cfm ± 10% for each FRVS ventilation unit.

g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration testing acceptance criteria of less than 0.05% in accordance with Regulatory Position C.5.a and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 9,000 cfm ± 10% for each FRVS ventilation unit.

3.6.5.3 FILTRATION, RECIRCULATION AND VENTILATION SYSTEM (FRVS) FRVS RECIRCULATION SUBSYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3.2 Six FRVS recirculation units shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and *.

ACTION:

a. With one or two of the above required FRVS recirculation units inoperable, restore all the inoperable unit(s) to OPERABLE status within 7 days, or:

   1. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   2. In Operational Condition *, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

b. With three or more of the above required FRVS recirculation units inoperable in Operational Condition *, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

c. With three or more of the above required FRVS recirculation units inoperable in OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.3.2 Each of the six FRVS recirculation units shall be demonstrated OPERABLE:

INSERT 2

a. ~~At least once per 14 days~~ by verifying that the water seal bucket traps have a water seal and making up any evaporative losses by filling the traps to the overflow.

INSERT 2

b. ~~At least once per 31 days~~ by initiating, from the control room, flow through the HEPA filters and verifying that the subsystem operates for at least 15 minutes.

*When recently irradiated fuel is being handled in the secondary containment and during operations with a potential for draining the reactor vessel.

INSERT 1

c. ~~At least once per 18 months~~ or upon determination** that the HEPA filters could have been damaged by structural maintenance or adversely affected by any foreign materials (1) after any structural maintenance on the HEPA filters or housings by:

1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a and C.5.c of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rates are 30,000 cfm ± 10% for each FRVS recirculation unit.

2. Verifying a subsystem flow rate of 30,000 cfm ± 10% for each FRVS recirculation unit during system operation when tested in accordance with ANSI N510-1980.

d. not used

**This determination shall consider the maintenance performed and/or the type, quantity, length of contact time, known effects and previous accumulation history for all contaminants which could reduce the system performance to less than that verified by the acceptance criteria in items c.1 and c.2 below.

SURVEILLANCE REQUIREMENTS (Continued)

e. ~~At least once per 18 months~~ by: INSERT 1

1. Verifying that the pressure drop across the exhaust duct is less than 8 inches Water Gauge in the recirculation filter train while operating the filter train at a flow rate of 30,000 cfm ± 10% for each FRVS recirculation unit.

2. Verifying that the filter train starts and isolation dampers open on each of the following test signals:

   a. Manual initiation from the control room, and

   b. Simulated automatic initiation signal.

f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration testing acceptance criteria of less than 0.05% in accordance with Regulatory Position C.5.a and C.5.c of Regulatory Guide 1.52, Revision 2 March 1978, while operating the system at a flow rate of 30,000 cfm ± 10% for each FRVS recirculation unit.

DRYWELL AND SUPPRESSION CHAMBER OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.6.6.2 The drywell and suppression chamber atmosphere oxygen concentration shall be less than 4% by volume.

APPLICABILITY: OPERATIONAL CONDITION 1*, during the time period:

a. Within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER, following startup, to

   Within 24 hours prior to reducing THERMAL POWER to less than 15% of RATED THERMAL POWER preliminary to a scheduled reactor shutdown.

ACTION:

With the drywell and/or suppression chamber oxygen concentration exceeding the limit, restore the oxygen concentration to within the limit within 24 hours or be in at least STARTUP within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 The drywell and suppression chamber oxygen concentration shall be verified to be within the limit within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER and ~~at least once per 7 days~~ thereafter.

INSERT 2

*See Special Test Exception 3.10.5.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. In OPERATIONAL CONDITION 4 or 5 with the SACS subsystem, which is associated with safety related equipment required OPERABLE by Specification 3.5.2, having two SACS pumps or one heat exchanger inoperable, declare the associated safety related equipment inoperable and take the ACTION required by Specification 3.5.2.

d. In OPERATIONAL CONDITION 5 with the SACS subsystem, which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, having two SACS pumps or one heat exchanger inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

e. In OPERATIONAL CONDITION 4, 5, or **, with one SACS subsystem, which is associated with safety related equipment required OPERABLE by Specification 3.8.1.2, inoperable, realign the associated diesel generators within 2 hours to the OPERABLE SACS subsystem, or declare the associated diesel generators inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

f. In OPERATIONAL CONDITION 4, 5, or **, with only one SACS pump and heat exchanger and its associated flowpath OPERABLE, restore at least two pumps and two heat exchangers and associated flowpaths to OPERABLE status within 72 hours or, declare the associated safety related equipment inoperable and take the associated ACTION requirements.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required safety auxiliaries cooling system subsystems shall be demonstrated OPERABLE:

INSERT 1

a. ~~At least once per 31 days~~ by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

INSERT 1

b. ~~At least once per 18 months~~ by verifying that: 1) Each automatic valve servicing safety-related equipment actuates to its correct position on the appropriate test signal(s), and 2) Each pump starts automatically when its associated diesel generator automatically starts.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. In OPERATIONAL CONDITION 4 or 5:

With only one station service water pump and its associated flowpath OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated SACS subsystem inoperable and take the ACTION required by Specification 3.7.1.1.

c. In OPERATIONAL CONDITION *:

With only one station service water pump and its associated flowpath OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated SACS subsystem inoperable and take the ACTION required by Specification 3.7.1.1. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.2 At least the above required station service water system loops shall be demonstrated OPERABLE:

INSERT 2

a. ~~At least once per 31 days~~ by verifying that each valve (manual, power operated or automatic), servicing safety related equipment that is not locked, sealed or otherwise secured in position, is in its correct position.

INSERT 2

b. ~~At least once per 18 months~~ by verifying that:

1. Each automatic valve servicing non-safety related equipment actuates to its isolation position on an isolation test signal.

2. Each pump starts automatically when its associated diesel generator automatically starts.

* When handling recently irradiated fuel in the secondary containment.

PLANT SYSTEMS

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The ultimate heat sink (Delaware River) shall be OPERABLE with:

a. A minimum river water level at or above elevation -9'0 Mean Sea Level, USGS datum (80'0 PSE&G datum), and

b. An average river water temperature of less than or equal to 85.0°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5 and *.

ACTION:

With the river water temperature in excess of 85.0°F, continued plant operation is permitted provided that both emergency discharge valves are open and emergency discharge pathways are available. With the river water temperature in excess of 88.0°F, continued plant operation is permitted provided that all of the following additional conditions are satisfied: all SSWS pumps are OPERABLE, all SACS pumps are OPERABLE, all EDGs are OPERABLE and the SACS loops have no cross-connected loads (unless they are automatically isolated during a LOP and/or LOCA); with ultimate heat sink temperature greater than 89°F and less than or equal to 91.4°F, verify once per hour that water temperature of the ultimate heat sink is less than or equal to 89°F averaged over the previous 24 hour period; otherwise, with the requirements of the above specification not satisfied:

a. In OPERATIONAL CONDITIONS 1, 2 or 3, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITIONS 4 or 5, declare the SACS system and the station service water system inoperable and take the ACTION required by Specification 3.7.1.1 and 3.7.1.2.

c. In Operational Condition *, declare the plant service water system inoperable and take the ACTION required by Specification 3.7.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The ultimate heat sink shall be determined OPERABLE:

a. By verifying the river water level to be greater than or equal to the minimum limit ~~at least once per 24 hours~~. INSERT 1

b. By verifying river water temperature to be within its limit:

INSERT 1

1) ~~at least once per 24 hours~~ when the river water temperature is less than or equal to 82°F.

INSERT 1

2) ~~at least once per 2 hours~~ when the river water temperature is greater than 82°F.

* When handling recently irradiated fuel in the secondary containment.

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION (continued)

2. With both control room emergency filtration subsystems inoperable for reasons other than Condition b.3, suspend handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

3. With one or more control room emergency filtration subsystems inoperable due to an inoperable CRE boundary##, immediately suspend handling of recently irradiated fuel and operations with a potential for draining the vessel.

c. The provisions of Specification 3.0.3 are not applicable in Operational Condition *.

SURVEILLANCE REQUIREMENTS

4.7.2.1 Each control room emergency filtration subsystem shall be demonstrated OPERABLE:

INSERT 1

a. ~~At least once per 12 hours~~ by verifying that the control room air temperature is less than or equal to 85°F#. INSERT 1

b. ~~At least once per 31 days on a STAGGERED TEST BASIS~~ by initiating, from the control room, the control area chilled water pump, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 hours with the heaters on in order to reduce the buildup of moisture on the carbon adsorbers and HEPA filters.

*When recently irradiated fuel is being handled in the secondary containment and during operations with a potential for draining the reactor vessel.

#This does not require starting the non-running control emergency filtration subsystem.

##The main control room envelope (CRE) boundary may be opened intermittently under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

INSERT 2

c. ~~At least once per 18 months~~ or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem filter train by:

1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system filter train flow rate is 4000 cfm $\pm$ 10%.

2. Verifying within 31 days after removal, that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity 70%.

3. Verifying a subsystem filter train flow rate of 4000 cfm $\pm$ 10% during subsystem operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal from the Control Room Emergency Filtration units that a laboratory analysis of a representative carbon sample, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows a methyl iodide penetration less than 0.5% when tested in accordance with ATSM D3803 - 1989 at a temperature of 30°C and a relative humidity of 70%.

e. ~~At least once per 18 months~~ by: INSERT 1

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 7.5 inches Water Gauge while operating the filter train subsystem at a flow rate of 4000 cfm $\pm$ 10%.

2. Verifying with the control room hand switch in the recirculation mode that on each of the below recirculation mode actuation test signals, the subsystem automatically switches to the isolation mode of operation and the isolation dampers close within 5 seconds:

3/4.7.3 FLOOD PROTECTION

LIMITING CONDITION FOR OPERATION

3.7.3 Flood protection shall be provided for all safety related systems, components and structures when the water level of the Delaware River reaches 6.0 feet Mean Sea Level (MSL) USGS datum (95.0 feet PSE&G datum) at the Service Water Intake Structure.

APPLICABILITY: At all times.

ACTION:

a. With severe storm warnings from the National Weather Service which may impact Artificial Island in effect or with the water level at the service water intake structure above elevation 6.0 feet MSL USGS datum (95.0 feet PSE&G datum), initiate and complete:

1. The closing of all service water intake structure watertight perimeter flood doors identified in Table 3.7.3-1 within 1 hour, or declare affected service water system components inoperable and take the actions required by LCO 3.7.1.2;

- and -

2. The closing of all power block watertight perimeter flood doors identified in Table 3.7.3-1 within 1.5 hours.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Once closed, all access through the doors shall be administratively controlled.

b. With the water level at the service water intake structure above elevation 10.5 feet MSL USGS datum (99.5 feet PSE&G datum), be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 The water level at the service water intake structure shall be determined to be within the limit by: INSERT 1

a. Measurement ~~at least once per 24 hours~~ when the water level is below elevation 6.0 MSL USGS datum (95.0 feet PSE&G datum), and

b. Measurement at least once per 4 hours when severe storm warnings from the National Weather Service which may impact Artificial Island are in effect. INSERT 1

c. Measurement ~~at least once per hour~~ when the water level is equal to or above elevation 6.0 MSL USGS datum (95.0 feet PSE&G datum).

PLANT SYSTEMS

3/4.7.4 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

Note: LCO 3.0.4.b is not applicable to RCIC.

With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.4 The RCIC system shall be demonstrated OPERABLE:

INSERT 2

a. ~~At least once per 31 days~~ by:

1. Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

2. Verifying that each valve, manual, power operated or automatic in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

3. Verifying that the pump flow controller is in the correct position.

b. When tested pursuant to Specification 4.0.5 by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1000 + 20, - 80 psig.*

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

SURVEILLANCE REQUIREMENTS (Continued)

INSERT 2

c. ~~At least once per 18 months~~ by:

1. Performing a system functional test which includes simulated automatic actuation and restart# and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests.

#Automatic restart on a low water level signal which is subsequent to a high water level trip.

PLANT SYSTEMS

3/4.7.6 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.6 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limit, withdraw the sealed source from use and either:

   1. Decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.6.2 Test Frequencies - Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

INSERT 1

a. Sources in use - ~~At least once per six months~~ for all sealed sources containing radioactive material:

   1. With a half-life greater than 30 days, excluding Hydrogen 3, and

   2. In any form other than gas.

PLANT SYSTEMS

3/4.7.7 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 24% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 2 hours or reduce THERMAL POWER to less than or equal to 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.7.7 The main turbine bypass system shall be demonstrated OPERABLE ~~at least once per~~:

INSERT 1

a. ~~31 days~~ by cycling each turbine bypass valve through at least one complete cycle of full travel, and

INSERT 1

b. ~~18 months~~ by:

1. Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve actuates to its correct position.

2. Demonstrating TURBINE BYPASS SYSTEM RESPONSE TIME meets the following requirements when measured from the initial movement of the main turbine stop or control valve:

   a) 80% of turbine bypass system capacity shall be established in less than or equal to 0.3 second.

   b) Bypass valve opening shall start in less than or equal to 0.1 second.

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

INSERT 1

a. Determined OPERABLE ~~at least once per 7 days~~ by verifying correct breaker alignments and indicated power avail~~ability, and~~

INSERT 2

b. Demonstrated OPERABLE ~~at least once per 18 months~~ during shutdown by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE: *

INSERT 1

a. ~~At least once per 31 days on a STAGGERED TEST BASIS~~ by:

1. Verifying the fuel level in the fuel oil day tank.

2. Verifying the fuel level in the fuel oil storage tank.

3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the fuel oil day tank.

4. Verifying each diesel generator starts** from standby conditions and achieves steady state voltage $\geq$ 3828 and $\leq$ 4580 volts and frequency of 60 $\pm$ 1.2 Hz.

5. Verifying the diesel generator is synchronized, loaded to between 4000 and 4400*** kw and operates with this load for at least 60 minutes.

* All engine starts and loading for the purpose of this surveillance testing may be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engine is minimized.

** A modified diesel generator start involving idling and gradual acceleration to synchronous speed may be used for this surveillance. When modified start procedures are not used, the time, voltage, and frequency tolerances of Surveillance Requirement 4.8.1.1.2.g must be met.

*** Momentary transients outside the load range do not invalidate this test.

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 325 psig.

8. Verifying the lube oil pressure, temperature and differential pressure across the lube oil filters to be within manufacturer's specifications.

INSERT 1

b. ~~At least once per 31 days~~ by visually examining a sample of lube oil from the diesel engine to verify absence of water.

INSERT 2

c. ~~At least once per 31 days~~ and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the fuel oil day tank.

INSERT 2

d. ~~At least once per 92 days~~ by removing accumulated water from the fuel oil storage tanks.

INSERT 2

e. ~~At least once per 31 days~~ by performing a functional test on the emergency load sequencer to verify operability.

f. In accordance with the surveillance interval specified in the Diesel Fuel Oil Testing Program and prior to the addition of new fuel oil to the storage tank, samples shall be taken to verify fuel oil quality. Sampling and testing of new and stored fuel oil shall be in accordance with the Diesel Fuel Oil Testing Program contained in Specification 6.8.4.e.

SURVEILLANCE REQUIREMENTS (Continued)

INSERT 2

g. ~~At least once per 184 days~~ by verifying each diesel generator starts from standby conditions and achieves ≥ 3950 volts and ≥ 58.8 Hz in ≤ 10 seconds after receipt of the start signal, and subsequently achieves steady state voltage ≥ 3828 and ≤ 4580 volts and frequency of 60 ± 1.2 Hz.

INSERT 1

h. ~~At least once per 18 months~~, during shutdown, by:

1. Deleted.

2. Verifying the diesel generator capability to reject a load of greater than or equal to that of the RHR pump motor for each diesel generator while maintaining voltage ≥ 3828 and ≤ 4580 volts and frequency at 60 ± 1.2 Hz.

3. Verifying the diesel generator capability to reject a load of 4430 kW without tripping. The generator voltage shall not exceed 4785 volts during and following the load rejection.

4. Simulating a loss of offsite power by itself, and:

   a) Verifying loss of power is detected and deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds after receipt of the start signal, energizes the autoconnected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained ≥ 3828 and ≤ 4580 volts and 60 ± 1.2 Hz during this test.

For any start of a diesel generator, the diesel may be loaded in accordance with the manufacturer's recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

10. Verifying the diesel generator's capability to:

    a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

    b) Transfer its loads to the offsite power source,

    c) Be restored to its standby status, and

    d) Diesel generator circuit breaker is open.

11. Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

12. Verifying that the fuel oil transfer pump transfers fuel oil from each fuel storage tank to the day tank of each diesel via the installed cross connection lines.

13. Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval.

14. **Deleted.**

INSERT 2

i. ~~At least once per 10 years~~ or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to at least 514 rpm in less than or equal to 10 seconds.

INSERT 2

j. ~~At least once per 10 years~~ by:

1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution or equivalent, and

2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000. INSERT 1

k. ~~At least once per refueling cycle~~[#] by:

1. Verifying the diesel generator operates for at least 24 hours. During the first 22 hours of this test, the diesel generator shall be loaded to between 4000 and 4400 kW[##] and during the remaining 2 hours of this test, the diesel generator shall be loaded to between 4652 and 4873 kW. The diesel generator shall achieve $\geq$ 3950 volts and $\geq$ 58.8 Hz in $\leq$ 10 seconds following receipt of the start signal and subsequently achieve steady state voltage $\geq$ 3828 and $\leq$ 4580 volts and frequency of 60 $\pm$ 1.2 Hz.

2. Within 5 minutes after completing 4.8.1.1.2.k.1, verify each diesel generator starts and achieves $\geq$ 3950 volts and $\geq$ 58.8 Hz in $\leq$ 10 seconds after receipt of the start signal, and subsequently achieves steady state voltage $\geq$ 3828 and $\leq$ 4580 volts and frequency of 60 $\pm$ 1.2 Hz.

- OR -

Operate the diesel generator between 4000 kW and 4400 kW for two hours. Within 5 minutes of shutting down the diesel generator, verify each diesel generator starts and achieves $\geq$ 3950 volts and $\geq$ 58.8 Hz in $\leq$ 10 seconds after receipt of the start signal, and subsequently achieves steady state voltage $\geq$ 3828 and $\leq$ 4580 volts and frequency of 60 $\pm$ 1.2 Hz. This test shall continue for at least five minutes.

4.8.1.1.3 Reports - Not used.

4.8.1.1.4 The buried fuel oil transfer piping's cathodic protection system shall be demonstrated OPERABLE ~~at least once per 2 months and at least once per year~~ by subjecting the cathodic protection system to a performance test. INSERT 1

\# For any start of a diesel generator, the diesel may be loaded in accordance with manufacturer's recommendations.

\## Momentary transients outside the load range do not invalidate this test.

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required batteries and chargers shall be demonstrated OPERABLE: INSERT 1

a. ~~At least once per 7 days~~ by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category A limits, and
2. Total battery terminal voltage for each 125-volt battery is greater than or equal to 129 volts on float charge and for each 250-volt battery the terminal voltage is greater than or equal to 258 volts on float charge.

INSERT 1

b. ~~At least once per 92 days~~ and within 7 days after a battery discharge with battery terminal voltage below 108 volts for a 125-volt battery or 210 volts for a 250-volt battery, or battery overcharge with battery terminal voltage above 140 volts for a 125-volt battery or 280 volts for a 250-volt battery, by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category B limits,
2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150×10^{-6} ohms, excluding cable intercell connections, and
3. The average electrolyte temperature of each sixth cell of connected cells is above 72°F.

INSERT 1

c. ~~At least once per 18 months~~ by verifying that:

1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,
2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material,
3. The resistance of each cell-to-cell and terminal connection is less than or equal to 150×10^{-6} ohms, excluding cable intercell connections, and
4. The battery charger will supply the current listed below at the voltage listed below for at least 8 hours.

CHARGER	Minimum Voltage	CURRENT (AMPERES)
1AD413, 1AD414	129	200
1BD413, 1BD414		
1CD413, 1CD414		
1CD444, 1DD414		
1DD444, 1DD413		
10D423, 10D433	258	50

SURVEILLANCE REQUIREMENTS (Continued)

INSERT 1

d. ~~At least once per 18 months~~ during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

INSERT 1

e. ~~At least once per 60 months~~ during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. ~~At this once per 60 month interval~~ this performance discharge test may be performed in lieu of the battery service test.

f. At least once per 18 months, during shutdown, performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating. At this once per 18 months interval, this performance discharge test may be performed in lieu of the battery service test.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one of the above required A.C. distribution system channels not energized, re-energize the channel within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required 125 volt D.C. distribution system channels not energized, re-energize the division within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any one of the above required 250 volt D.C. distribution systems not energized, declare the associated HPCI or RCIC system inoperable and apply the appropriate ACTION required by the applicable Specifications.

d. With one or both inverters in one channel inoperable, energize the associated 120 volt A.C. distribution panel(s) within 8 hours, and restore the inverter(s) to OPERABLE status within 24 hours; or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system channels shall be determined energized ~~at least once per 7 days~~ by verifying correct breaker/switch alignment and voltage on the busses/MCCs/panels.

INSERT 2

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With less than two channels of the above required A.C. distribution system energized, suspend CORE ALTERATIONS, handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

b. With less than two channels of the above required D.C. distribution system energized, suspend CORE ALTERATIONS, handling of recently irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system channels shall be determined energized ~~at least once per 7 days~~ by verifying correct breaker/switch alignment and voltage on the busses/MCCs/panels.

INSERT 2

*When handling recently irradiated fuel in the secondary containment.

ELECTRICAL POWER SYSTEMS

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.1 All primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 inoperable, declare the affected system or component inoperable and apply the appropriate ACTION statement for the affected system, and

   1. For 4.16 kV circuit breakers, de-energize the 4.16 kV circuit(s) by tripping the associated redundant circuit breaker(s) within 72 hours and verify the redundant circuit breaker to be tripped at least once per 7 days thereafter.

   2. For 480 volt circuit breakers, remove the inoperable circuit breaker(s) from service by disconnecting* the breaker within 72 hours and verify the inoperable breaker(s) to be disconnected at least once per 7 days thereafter.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.8.4.1 Each of the primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be demonstrated OPERABLE:

a. ~~At least once per 18 months~~: INSERT 2

   1. By verifying that each of the medium voltage 4.16 kV circuit breakers are OPERABLE by performing:

      a) A CHANNEL CALIBRATION of the associated protective relays, and

      b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed.

*After being disconnected, these breakers shall be maintained disconnected under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

2. By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall consist of injecting a current with a value between 150% and 300% of the pickup of the long time delay trip element and verifying that the circuit breaker operates within the time delay bandwidth for that current specified by the manufacturer. The instantaneous element shall be tested by injecting a current in excess of 120% the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay. Molded case circuit breaker testing shall also follow this procedure except that generally no more than two trip elements, time delay and instantaneous, will be involved. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

INSERT 2

b. ~~At least once per 60 months~~ by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection bypass circuit of each motor operated valve (MOV) required to have thermal overload protection shall be OPERABLE.

APPLICABILITY: Whenever the MOV is required to be OPERABLE.

ACTION:

With the thermal overload protection bypass circuit for one or more of the above required MOVs inoperable, restore the inoperable thermal overload protection bypass circuit(s) to OPERABLE status within 8 hours or declare the affected MOV(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection bypass circuit for each of the above required MOVs shall be demonstrated OPERABLE:

INSERT 1

a. ~~At least once per 18 months~~ by the performance of a CHANNEL FUNCTIONAL TEST for:

1. Those thermal overload protection devices which are normally in force during plant operation and bypassed only under accident conditions.

2. A representative sample of at least 25% of those thermal overload protection devices which are bypassed continuously and temporarily placed in force only when the MOVs are undergoing periodic or maintenance testing~~, such that the bypass circuitry for each thermal overload protection device of this type is tested at least once per 6 years~~.

3. A representative sample of at least 25% of those thermal overload protection devices which are in force during normal manual (momentary push button contact) MOV operation and bypassed during remote manual (push button held depressed) MOV operation~~, such that the bypass circuitry for each thermal overload protection device of this type is tested at least once per 6 years~~.

b. Following maintenance on the motor starter.

4.8.4.2.2 The thermal overload protection for the above required MOVs which are continuously bypassed and temporarily placed in force only when the MOV is undergoing periodic or maintenance testing shall be verified to be continuously bypassed following such testing.

ELECTRICAL POWER SYSTEMS

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (NOT BYPASSED)

LIMITING CONDITION FOR OPERATION

3.8.4.3 The thermal overload protection of each motor operated valve (MOV) shown in Table 3.8.4.3-1 shall be OPERABLE.

APPLICABILITY: Whenever the MOV is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required MOVs inoperable, restore the inoperable thermal overload(s) to OPERABLE status within 8 hours or declare the affected MOV(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.3 The thermal overload protection for each of the above required MOVs shall be demonstrated OPERABLE ~~at least once per 18 months~~ and following maintenance on the motor starter by the performance of a CHANNEL CALIBRATION.

INSERT 1

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.4 Two RPS electric power monitoring channels for each inservice RPS MG set or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service.

b. With both RPS electric power monitoring channels for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.4 The above specified RPS electric power monitoring channels shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed in the previous 6 months.

INSERT 1

b. ~~At least once per 18 months~~ by demonstrating the OPERABILITY of over-voltage, under-voltage, and under-frequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints.

1. Over-voltage $\leq$ 132 VAC, (Bus A), 132 VAC (Bus B)

2. Under-voltage $\geq$ 108 VAC, (Bus A), 108 VAC (Bus B)

3. Under-frequency $\geq$ 57 Hz. (Bus A and Bus B)

ELECTRICAL POWER SYSTEMS

CLASS 1E ISOLATION BREAKER OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.5 All Class 1E isolation breaker (tripped by a LOCA signal) overcurrent protective devices shown in Table 3.8.4.5-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the overcurrent protective devices shown in Table 3.8.4.5-1 inoperable, declare the affected isolation breaker inoperable and remove the inoperable circuit breaker(s) from service within 72 hours and verify the inoperable breaker(s) to be disconnected at least once per 7 days thereafter.

SURVEILLANCE REQUIREMENTS

4.8.4.5 Each of the Class 1E isolation breaker overcurrent protective devices shown in Table 3.8.4.5-1 shall be demonstrated OPERABLE:

a. ~~At least once per 18 months~~ INSERT 2

By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall consist of injecting a current with a value between 150% and 300% of the pickup of the long time delay trip element and a value between 150% and 250% of the pickup of the short time delay, and verifying that the circuit breaker operates within the time delay band width for that current specified by the manufacturer. The instantaneous element shall be tested by injecting a current in excess of 120% of the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay. Molded case circuit breaker testing shall also follow this procedure except that generally no more than two trip elements, time delay and instantaneous, will be involved. For circuit breakers equipped with solid state trip devices, the functional testing may be performed with use of portable instruments designed to verify the time-current characteristics and pickup calibration of the trip elements. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

b. ~~At least once per 60 months~~ INSERT 2 by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

POWER RANGE NEUTRON MONITORING SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.6 The power range neutron monitoring system (NMS) electric power monitoring channels for each inservice power range NMS power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one power range NMS electric power monitoring channel for an inservice power range NMS power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or deenergize the associated power range NMS power supply feeder circuit.

b. With both power range NMS electric power monitoring channels for an inservice power range NMS power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or deenergize the associated power range NMS power supply feeder circuit.

SURVEILLANCE REQUIREMENTS

4.8.4.6 The above specified power range NMS electric power monitoring channels shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed in the previous 6 months.

INSERT 2

b. ~~At least once per 18 months~~ by demonstrating the OPERABILITY of over-voltage, under-voltage, and under-frequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints.

1. Over-voltage $\leq$ 132 VAC (BUS A), 132 VAC (BUS B)

2. Under-voltage $\geq$ 108 VAC (BUS A), 108 VAC (BUS B)

3. Under-frequency $\geq$ 57 Hz. -0, +2%

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified:

a. Within 2 hours prior to:

1. Beginning CORE ALTERATIONS, and

2. Resuming CORE ALTERATIONS when the reactor mode switch has been unlocked.

b. ~~At least once per 12 hours~~. INSERT 1

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks* shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST within 24 hours prior to the start of and ~~at least once per 7 days~~ during control rod withdrawal or CORE ALTERATIONS, as applicable. INSERT 1

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks* that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

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*The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least 2 source range monitor* (SRM) channels shall be OPERABLE and inserted to the normal operating level with:##

a. Annunciation and continuous visual indication in the control room,

b. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

c. Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, the "shorting links" removed from the RPS circuitry prior to and during the time any control rod is withdrawn.#

d. During a SPIRAL UNLOAD, the count rate may drop below 3 cps when the number of assemblies remaining in the core drops to sixteen or less.

e. During a SPIRAL RELOAD, up to four fuel assemblies may be loaded in the four bundle locations immediately surrounding each of the four SRMs prior to obtaining 3 cps. Until these assemblies have been loaded, the 3 cps count rate is not required.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. ~~At least once per 12 hours:~~ INSERT 2

1. Performance of a CHANNEL CHECK,

---

*The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

#Not required for control rods removed per Specification 3.9.10.1 and 3.9.10.2.

##Three SRM channels shall be OPERABLE for critical shutdown margin demonstrations. An SRM detector may be retracted provided a channel indication of at least 100 cps is maintained.

2. Verifying the detectors are inserted to the normal operating level, and

3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 7 days.~~ INSERT 1

c. Verifying that the channel count rate is at least 3 cps.

1. Prior to control rod withdrawal, INSERT 1

2. Prior to and ~~at least once per 12 hours~~ during CORE ALTERATIONS***, and

3. ~~At least once per 24 hours~~**. INSERT 1

d. Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, verifying that the RPS circuitry "shorting links" have been removed, within 8 hours prior to and ~~at least once per 12 hours~~ during the time any control rod is withdrawn.**
INSERT 1

** Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** Except as noted in Specifications 3.9.2.d and 3.9.2.e.

3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS, except that one control rod may be withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified:

a. Within 2 hours prior to:

1. The start of CORE ALTERATIONS.

2. The withdrawal of one control rod under the control of the reactor mode switch Refuel position one-rod-out interlock.

b. ~~At least once per 12 hours.~~ INSERT 2

* Except control rods removed per Specification 3.9.10.1 or 3.9.10.2.
**See Special Test Exception 3.10.3.

3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least 22 feet 2 inches of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and ~~at least once per 24 hours~~ INSERT 1 during handling of fuel assemblies or control rods within the reactor pressure vessel.

3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.9 At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage pool area after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the spent fuel storage pool shall be determined to be at least at its minimum required depth ~~at least once per 7 days~~ INSERT 2

SURVEILLANCE REQUIREMENTS

INSERT 1

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ thereafter until a control rod and associated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1.c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

f. All fuel loading operations are suspended.

SURVEILLANCE REQUIREMENTS

INSERT 1

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

f. All fuel loading operations are suspended.

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 At least one shutdown cooling mode loop of the residual heat removal (RHR) system shall be OPERABLE and in operation* with:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22 feet 2 inches above the top of the reactor pressure vessel flange and heat losses to ambient** are not sufficient to maintain OPERATIONAL CONDITION 5.

ACTION:

a. With no RHR shutdown cooling mode loop OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal. Otherwise, suspend all operations involving an increase in the reactor decay heat load and establish SECONDARY CONTAINMENT INTEGRITY within 4 hours.

b. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours~~. → INSERT 2

---

* The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

** Ambient losses must be such that no increase in reactor vessel water temperature will occur (even though REFUELING conditions are being maintained).

REFUELING OPERATIONS

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and at least one loop shall be in operation,* with each loop consisting of:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22 feet 2 inches above the top of the reactor pressure vessel flange and heat losses to ambient** are not sufficient to maintain OPERATIONAL CONDITION 5.

ACTION:

a. With less than the above required shutdown cooling mode loops of the RHR system OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the OPERABILITY of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours.~~ → INSERT 2

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

**Ambient losses must be such that no increase in reactor vessel water temperature will occur (even though REFUELING conditions are being maintained).

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3 and 3.9.1 and Table 1.2 may be suspended to permit the reactor pressure vessel closure head and the drywell head to be removed and the primary containment air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ during low power PHYSICS TESTS.

INSERT 1

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3 and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

a. The source range monitors are OPERABLE with the RPS circuitry "shorting links" removed per Specification 3.9.2.

b. The rod worth minimizer is OPERABLE per Specification 3.1.4.1 and is programmed for the shutdown margin demonstration, or conformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The "rod-out-notch-override" control shall not be used during out-of-sequence movement of the control rods.

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

INSERT 2

4.10.3 Within 30 minutes prior to and ~~at least once per 12 hours~~ during the performance of a shutdown margin demonstration, ~~verify that;~~

a. The source range monitors are OPERABLE per Specification 3.9.2,

b. The rod worth minimizer is OPERABLE with the required program per Specification 3.1.4.1 or a second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

SPECIAL TEST EXCEPTIONS

3/4.10.4 RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation with matched pump speed may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours ~~at least once per hour~~ during PHYSICS TESTS.
INSERT 2

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER ~~at least once per hour~~ during PHYSICS TESTS.
INSERT 2

3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ during training startups.

INSERT 2

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in any outside temporary tank shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Radioactive Effluent Release Report, pursuant to Specification 6.9.1.7.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each of the above tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents ~~at least once per 7 days~~ when radioactive materials are being added to the tank. INSERT 1

RADIOACTIVE EFFLUENTS

MAIN CONDENSER

LIMITING CONDITION FOR OPERATION

3.11.2.7 The radioactivity rate of noble gases measured at the recombiner after-condenser discharge shall be limited to less than or equal to 3.30 E+5 microcuries/sec after 30 minute decay.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3*.

ACTION:

With the radioactivity rate of noble gases at the recombiner after-condenser discharge exceeding 3.30 E+5 microcuries/sec after 30 minute decay, restore the radioactivity rate to within its limit within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.11.2.7.1 The radioactivity rate of noble gases at the recombiner after-condenser discharge shall be continuously monitored in accordance with Specification 3.3.7.1.

4.11.2.7.2 The radioactivity rate of noble gases from the recombiner after-condenser discharge shall be determined to be within the limits of Specification 3.11.2.7 at the following frequencies by performing an isotopic analysis of a representative sample of gases taken near the discharge of the main condenser air ejector:

a. ~~At least once per 31 days~~ → INSERT 2

b. Within 4 hours following an increase, as indicated by the Offgas Pretreatment Radiation Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level, in the nominal steady-state fission gas release from the primary coolant.

c. The provisions of Specification 4.0.4 are not applicable.

*When the main condenser air ejector is in operation.

PROCEDURES AND PROGRAMS (Continued)

6.8.4.g. Radioactive Effluent Controls Program

8) Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from the unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from the unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on venting and purging of the containment through the Reactor Building Ventilation System, Hardened Torus Vent, or the FRVS to maintain releases as low as reasonably achievable, and

11) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

h. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluents monitoring program and modeling of the environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in an Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

6.8.4.j INSERT 3

ATTACHMENT 4 (Information Only)

TECHNICAL SPECIFICATION BASES PAGES WITH PROPOSED CHANGES:LICENSE AMENDMENT TO ADOPT TSTF-425, REVISION 3, "RELOCATE SURVEILLANCE FREQUENCIES TO LICENSEE CONTROL"

The following Technical Specification Bases Pages for HCGS (Facility Operating License NPF-57) are affected by this change request:

B 3/4 1-2	B 3/4 3-16
B 3/4 1-2a	B 3/4 3-17
B 3/4 1-2b	B 3/4 4-2
B 3/4 1-2c	B 3/4 4-3
B 3/4 1-4	B 3/4 5-1
B 3/4 3-1	B 3/4 6-5
B 3/4 3-2q	B 3/4 6-8
B 3/4 3-2r	B 3/4 6-9
B 3/4 3-3	B 3/4 6-12
B 3/4 3-4	B 3/4 6-13
B 3/4 3-11	B 3/4 6-14
B 3/4 3-12	B 3/4 8-1d

INSERT 1

In accordance with the Surveillance Frequency Control Program

INSERT 2

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This page reflects pending LAR H09-03 Change

REACTIVITY CONTROL SYSTEMS
BASES

3/4.1.3 CONTROL RODS

The specifications of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) limit the potential effects of the rod drop accident. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

The operability of an individual control rod is based on a combination of factors, primarily, the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator operability is addressed by LCO 3.1.3.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring a control rod inoperable. Although not all control rods are required to be operable to satisfy the intended reactivity control requirements, control over the number of inoperable control rods is required.

Control rod insertion capability is demonstrated by surveillance 4.1.3.1.2 inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This 31 day exercise test ensures the control rod is not stuck and is free to insert on a scram signal. Experience with this control system, and analysis performed for an industry-wide BWR initiative that was approved by the NRC[1] have indicated that testing on a 31 day period is adequate, and rods which move by drive pressure will scram when required as the pressure applied is much higher. At any time, a control rod is immovable for reasons not associated with the control rod drive mechanism, a determination of that control rod's trippability (Operability) must be made and appropriate actions taken. As an example, if the control rod can be scrammed, but can not be moved due to a RMCS failure, the rod(s) may continue to be considered OPERABLE provided all other related surveillances are current.

Damage within the control rod drive mechanism could be a generic problem, therefore with a withdrawn control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

(1) TSTF/CLIIP-475, Rev.1, Federal Register Note 72FR63935, dated November 13, 2007.

LAR H09-06
pending changes

CONTROL RODS (Continued)

~~The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding Safety Limit during the limiting power transient analyzed in Section 15.4 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than the fuel cladding Safety Limit. The occurrence of scram times longer than those specified should be viewed as an indication of a systematic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.~~

Insert 2
from LAR H09-06

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed. The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.

In OPCON 1 and 2, the scram function is required for mitigation of DBAs and transients, and therefore the scram accumulators must be OPERABLE to support the scram function. In OPCON 3 and 4, control rods are only allowed to be withdrawn under limits imposed by the reactor mode switch being in shutdown and by the control rod block being applied. This provides adequate requirements for control rod scram accumulator OPERABILITY during these conditions. In OPCON 5, withdrawn control rods are required to have OPERABLE accumulators.

The actions of Specification 3.1.3.5 are modified by a note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the required Actions for each Condition provide appropriate compensatory actions for each affected accumulator. Complying with the Required Actions may allow for continued operation and subsequent affected accumulators governed by subsequent Condition entry and application of associated Required Actions.

Insert 3
from LAR H09-06
No impact

With two or more control rod scram accumulators inoperable and reactor pressure ≥ 900 psig, adequate pressure must be supplied to the charging water header. With inadequate charging water pressure, the accumulators could restoring compliance with BPWS or restoring the control rods to OPERABLE status, an evaluation of the postulated CRDA may be performed to verify that the maximum incremental rod worth of an assumed dropped control rod would not result in exceeding the CRDA design limit of 280 cal/gm fuel enthalpy and would not result in unacceptable dose consequences due to the number of fuel rods exceeding 170 cal/gm fuel enthalpy as described in the UFSAR. The allowed Completion Time of 8 hours is acceptable, considering the low probability of a CRDA occurring.

In addition to the separation requirements for inoperable control rods, an assumption in the CRDA analysis is that no more than three inoperable control rods are allowed in any one BPWS group. Therefore, with one or more BPWS groups having four or more inoperable control rods, the control rods must be restored to OPERABLE status. LCO 3.1.3.1.d is modified by a Note indicating that the Condition is not applicable when THERMAL POWER is > 8.6% RTP since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.4. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

Insert 2 (LAR-H09-06)

Verifying that the scram time for each control rod to notch position 05 is ≤ 7 seconds (SR 4.1.3.2) provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 4.1.3.3.

The scram times specified in Table 3.1.3.3-1 (in the accompanying LCO) are required to ensure that the scram reactivity assumed in the Design Basis Accident (DBA) and transient analysis is met (Ref. 2). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.3.3-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows up to approximately 7% of the control rods (e.g., 185 x 7% = 13) to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3.1, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens ("dropout") as the index tube travels upward. Verification of the specified scram times in Table 3.1.3.3-1 is accomplished through measurement of the "dropout" times. To ensure that local scram reactivity rates are maintained within acceptable limits, no more than two of the allowed "slow" control rods may occupy adjacent locations.

Table 3.1.3.3-1 is modified by two Notes which state that control rods with scram times not within the limits of the Table are considered "slow" and that control rods with scram times > 7 seconds are considered inoperable as required by SR 4.1.3.2.

This LCO (3.1.3.3) applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3.1). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

Insert 2, LAR H09-06, continued

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following a shutdown ≥ 120 days or longer, control rods are required to be tested before exceeding 40% RTP following the shutdown. This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the associated core cell and by work on control rods or the CRD System.

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be "slow." With more than 7.5% of the sample declared to be "slow" per the criteria in Table 3.1.3.3-1, additional control rods are tested until this 7.5% criterion (e.g., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods (throughout the core, from all surveillances) exceeds the LCO limit. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data may have been previously tested in a sample. ~~The 200 day Frequency is based on operating experience that has shown control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable based on the additional Surveillances done on the CRDs at more frequent intervals in accordance with LCO 3.1.3.1 and LCO 3.1.3.5 "Control Rod Scram Accumulators."~~

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate the affected control rod is still within acceptable limits. The limits for reactor pressures < 800 psig are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. Limits for ≥ 800 psig are found in Table 3.1.3.3-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of Table 3.1.3.3-1, Note 2, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times are (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator, isolation valve or check valve in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

CONTROL RODS (Continued)

become inoperable, resulting in a potential degradation of the scram performance. Therefore, within 20 minutes from discovery of charging water header pressure < 940 psig concurrent with conditions in Action 3.1.3.5.a.2, adequate charging water header pressure must be restored. The allowed Completion Time of 20 minutes is reasonable, to place a CRD pump into service to restore the charging header pressure, if required. This Completion Time is based on the ability of the reactor pressure alone to fully insert all control rods.

Insert 4

LAR H09-06

no impact

With one or more control rod scram accumulators inoperable and the reactor pressure < 900 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor pressure < 900 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 940 psig, concurrent with conditions in Action 3.1.3.5.a.3, all control rods associated with inoperable accumulators must be verified to be fully inserted. Withdrawn control rods with inoperable accumulators may fail to scram under these low pressure conditions. The associated control rods must also be inserted, declared inoperable, and disarmed within 1 hour. The allowed Completion Time of 1 hour is reasonable considering the low probability of DBA or transient occurring during the time that the accumulator is inoperable.

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with loss of the CRD charging pump (Required Actions 3.1.3.5.a.2.a or 3.1.3.5.a.3.a) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

INSERT 1

Surveillance Requirement 4.1.3.5 requires that the accumulator pressure be checked ~~every 7 days~~ to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. ~~The 7 day frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.~~

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position

CONTROL RODS (Continued)

feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 6 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

~~The required surveillance intervals are adequate to determine that the rods are OPERABLE and not so frequent as to cause wear on the system components.~~

INSERT 2

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and imperfect mixing, this concentration is increased by 25%. The generic design basis of the standby liquid control system provides a specified cold shutdown boron concentration in the reactor core. The standby liquid control system was typically designed to inject the cold shutdown boron concentration in 90 to 120 minutes. The time requirement was selected to override the reactivity insertion rate due to cool down following the xenon poison peak. The pumping rate of 41.2 gpm meets the requirement.

The minimum storage volume of the solution is established to include the generic shutdown requirement and to allow for the portion below the pump suction nozzle that cannot be inserted. An additional allowance in the standby liquid control storage volume is provided to account for storage tank instrument inaccuracy and drift. Even with the maximum specified instrument inaccuracy and drift, the required quantity of sodium pentaborate solution is always available for injection.

A normal quantity of 4640 gallons of sodium pentaborate solution having a 14.0 percent concentration is required to meet the shutdown requirements. The temperature requirement for sodium pentaborate solution and the pump suction piping is necessary to ensure the sodium pentaborate remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume ~~once each 24 hours~~ assures that the solution is available for use.

Replacement of the explosive charges in the valves ~~at regular intervals~~ will assure that these valves will not fail because of deterioration of the charges.

The ATWS Rule (10 CFR 50.62) requires the addition of a new design requirement to the generic standby liquid control system design basis. Changes to flow

INSERT 2

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. INSERT 2 ~~Specified surveillance intervals and~~ surveillance and maintenance outage times have been determined in accordance with NEDC-30851P, "Technical Specification Improvement Analyses for BWR Reactor Protection System," as approved by the NRC and documented in the SER (letter to T. A. Pickens from A. Thadani dated July 15, 1987). The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

INSERT 1

The measurement of response time ~~at the specified frequencies~~ provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Selected sensor response time testing requirements were eliminated based upon NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Reactor Protection System Response Times are located in UFSAR Table 7.2-3.

As noted, the SR for the APRM Neutron Flux - Upscale, Setdown channel functional test is not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1, since testing of the OPERATIONAL CONDITION 2 required APRM Function cannot be performed in OPERATIONAL CONDITION 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into OPERATIONAL CONDITION 2 if the ~~7 day~~ frequency is not met per SR 4.0.2. In this event, the SR must be performed within 12 hours after entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

ACTIONS (continued)

inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), the Action required by Table 3.3.2-1 must be taken.

If there are no OPERABLE channels for a trip function in one trip system, and the inoperable channels cannot be restored to OPERABLE status within one hour, the inoperable channels must be placed in the tripped condition per Action 3.3.2.b.1.a. Alternately, if it is not desired to place the channels in trip, the Action required by Table 3.3.2-1 must be taken.

Footnote (e) to Table 3.3.2-1 modifies the minimum OPERABLE channels per trip function requirement to state that sensors are arranged per valve group, not per trip system. Where the trip function actuates a single valve group, Action 3.3.2.b applies for all cases in which less than the minimum required number of channels are OPERABLE. For trip functions annotated by footnote (e), Action 3.3.2.b.1.a applies when neither isolation logic (inboard or outboard) meets the minimum OPERABLE channels requirement.

For trip functions 1.e, 2.c and 2.d, a minimum of three OPERABLE channels per trip system are required. For these trip functions, three radiation monitoring channels input to four two-out-of-three PCIS initiation logics. When one RFE-RMS or one RBE-RMS channel is inoperable, Action 3.3.2.b.1.c applies. When more than one RFE-RMS or more than one RBE-RMS channel is inoperable, Action 3.3.2.b.1.a applies because a sufficient number of inputs would not be available to satisfy the actuation logic for any PCIS channel.

INSERT 2

SURVEILLANCE REQUIREMENTS

~~Specified surveillance intervals and~~ surveillance and maintenance outage ~~times have been~~ determined in accordance with References 5 and 6.

When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. Selected sensor response time testing requirements were eliminated based upon Reference 7, NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Isolation System Instrumentation Response Times are located in UFSAR Table 7.3-16.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

REFERENCES

1. UFSAR, Section 6.3.

2. UFSAR, Chapter 15.

3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.

4. UFSAR, Section 15.7.4.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," as approved by the NRC and documented in the SER (letter to D.N. Grace from C.E. Rossi dated January 6, 1989).

7. NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994).

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. ECCS actuation instrumentation is eliminated from response time testing requirements based on NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Emergency Core Cooling System Response Times are located in UFSAR Table 7.3-17. INSERT 2

~~Specified surveillance intervals and~~ surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2. The safety evaluation reports documenting NRC approval of NEDC-30936P-A are contained in letters to D. N. Grace from A. C. Thadani (Part 1) and C. E. Rossi (Part 2) dated December 9, 1988. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

INSERT 2

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 24% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression (135 ms @ 100% RTP), and the response time of the system logic.

~~Specified surveillance intervals and~~ surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

INSERT 2

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. ~~Specified surveillance intervals and~~ surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2 and GENE-770-06-2-A. "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications." The safety evaluation reports documenting NRC approval of NEDC-30936P-A and GENE-770-06-2-A are contained in letters to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1), D. N. Grace to C. E. Rossi dated December 9, 1988 (Part 2), and G. J. Beck from C. E. Rossi dated September 13, 1991.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

As noted, the SR for the Reactor Mode Switch Shutdown Position functional test is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into OPERATIONAL CONDITIONS 3 and 4 if the ~~18 month~~ frequency is not met per SR 4.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63 and 64.

INSTRUMENTATION

BASES

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION (continued)

The allowed completion time of 12 hours is reasonable, based on operating experience, to reach OPERATIONAL CONDITION 3 from full power conditions, or to remove the mechanical vacuum pump(s) from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

ACTION c.

ACTION c. allows that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated ACTIONs may be delayed for up to 6 hours provided mechanical vacuum pump trip capability is maintained. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the required ACTIONs taken. This allowance is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the mechanical vacuum pump will trip when necessary.

Surveillance Requirement 4.3.10.a

INSERT 1

Performance of the CHANNEL CHECK ~~once every 12 hours~~ ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

~~The frequency is based upon operating experience that demonstrates channel failure is rare.~~ The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

Surveillance Requirement 4.3.10.b

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION (continued)

~~The frequency of 92 days is based on the reliability analysis of Reference 2.~~

Surveillance Requirement 4.3.10.c

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. ~~The 18 month frequency is conservative with respect to the assumption of the calibration interval in the determination of the magnitude of instrument drift in the setpoint analysis.~~ For the purpose of this surveillance, normal background is the dose level experienced at 100% rated thermal power with hydrogen water chemistry at the maximum injection rate. The trip setpoint for the Main Steam Line Radiation - High, High trip function and requirements for setpoint adjustment are specified in Technical Specification 3.3.2.

Surveillance Requirement 4.3.10.d

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breaker is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if the breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

~~The 18 month frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.~~

REFERENCES

1. UFSAR, Section 15.4.9.5.1.2

2. NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989

INSTRUMENTATION

BASES

3/4.3.11 Oscillation Power Range Monitor (OPRM)

SURVEILLANCE REQUIREMENTS

SR 4.3.11.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. ~~A Frequency of 184 days provides an acceptable level of system average availability over the Frequency and is based on the reliability of the channel (Ref. 7).~~

INSERT 2

SR 4.3.11.2

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the OPRM System. ~~The 1000 EFPH Frequency is based on operating experience with LPRM sensitivity changes.~~ This surveillance is satisfied in accordance with Note f, Table 4.3.1.1-1 of TS 3/4.3.1.

INSERT 2

SR 4.3.11.3

The CHANNEL CALIBRATION is a complete check of the instrument loop. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology.

Calibration of the channel provides a check of the internal reference voltage and the internal processor clock frequency. It also compares the desired trip setpoints with those in processor memory. Since the OPRM is a digital system, the internal reference voltage and processor clock frequency are, in turn, used to automatically calibrate the internal analog to digital converters. The Allowable Values are specified in the CORE OPERATING LIMITS REPORT.

As noted, neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the ~~1000 EFPH~~ LPRM calibration using the TIPs (SR 4.3.11.2).

~~The Frequency of 18 months is based upon the design objective that the OPRM operate over a complete fuel cycle, as a minimum, without requiring calibration.~~

INSERT 2

SR 4.3.11.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods and scram discharge volume (SDV) vent and drain valves in Specification 3.1.3.1, "Control Rod OPERABILITY" overlaps this Surveillance to provide complete testing of the assumed safety function. The OPRM self-test function may be utilized to perform this testing for those components that it is designed to monitor.

~~The 18-month Frequency is based on engineering judgment and reliability of the components. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month Frequency.~~

INSERT 2

INSTRUMENTATION

BASES

3/4.3.11 Oscillation Power Range Monitor (OPRM)

SURVEILLANCE REQUIREMENTS (continued)

SR 4.3.11.5

This SR ensures that trips initiated from the OPRM system are not inadvertently bypassed when the capability of the OPRM system to initiate an RPS trip is required. The trip capability of the OPRM system is only required during operation under conditions susceptible to anticipated T-H instability oscillations. The region of anticipated oscillation is defined by THERMAL POWER ≥ 26.1% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow.

The trip capability of individual OPRM modules is automatically enabled based on the APRM power and flow signals associated with each OPRM channel during normal operation. These channel specific values of APRM power and recirculation drive flow are subject to surveillance requirements associated with other RPS functions such as APRM flux and flow biased simulated thermal power with respect to the accuracy of the signal to the process variable. The OPRM is a digital system with calibration and manually initiated tests to verify digital input including input to the auto-enable calculations. Periodic calibration confirms that the auto-enable function occurs at appropriate values of APRM power and recirculation flow signal. Therefore, verification that OPRM modules are enabled at any time that THERMAL POWER ≥ 26.1% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow adequately ensures that trips initiated from the OPRM system are not inadvertently bypassed.

The trip capability of individual OPRM modules can also be enabled by placing the module in the non-bypass (Manual Enable) mode. If placed in the non-bypass or Manual Enable mode the trip capability of the module is enabled and this SR is met. ~~The frequency of 18 months is based on engineering judgment and reliability of the components.~~

SR 4.3.11.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis (Ref. 8). The OPRM self-test function may be utilized to perform this testing for those components it is designed to monitor. The RPS RESPONSE TIME acceptance criteria are included in Reference 8.

INSERT 1

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. RPS RESPONSE TIME tests are conducted ~~such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system. This Frequency is based upon operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.~~

3/4.4.1 RECIRCULATION SYSTEM (continued)

at least once per operating cycle. These relationships should be periodically trended during an operating cycle to determine if the surveillance needs to be performed more than once in an operating cycle. Some of the phenomena to consider are: 1) The core flow resistance may decrease during the operating cycle, requiring lower recirculation pump speeds to achieve a given core flow at the end of the operating cycle versus the beginning, 2) Significant changes in fuel design can affect the relationship of recirculation drive flow to jet pump loop flow, 3) Significant changes in recirculation loop hydraulic characteristics can affect the relationship of recirculation pump speed to recirculation drive flow, and 4) Recirculation system instrument calibrations can impact any of the relationships The MG set scoop tube mechanical and electrical settings should account for the effects of such phenomena so that the maximum core flow assumed in the establishment of the MCPR and LHGR operating limits is protected.

An inoperable jet pump is not in itself a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis accident, increase the blowdown area and reduce the capability of reflooding the core, thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1375 psig in accordance with the ASME Code. A total of 13 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case transient.

~~Demonstration of the safety relief valve lift settings occurs only during shutdown. The safety relief valve/pilot stage assemblies are set pressure tested in accordance with the recommendations of General Electric~~

INSERT 2

3/4.4.2 SAFETY/RELIEF VALVES (continued)

SIL No. 196, Supplement 14 (April 23, 1984), "Target Rock 2-Stage SRV Set-Point Drift." Set pressure tests of the safety relief valve main (mechanical) stage are conducted ~~at least once every 5 years~~. INSERT 1

The low-low set system ensures that safety/relief valve discharges are minimized for a second opening of these valves, following any overpressure transient. This is achieved by automatically lowering the closing setpoint of two valves and lowering the opening setpoint of two valves following the initial opening. In this way, the frequency and magnitude of the containment blowdown duty cycle is substantially reduced. Sufficient redundancy is provided for the low-low set system such that failure of any one valve to open or close at its reduced setpoint does not violate the design basis.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems", May 1973 and Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping."

Proceduralized, manual quantitative monitoring and calculation of leakage rates, found by the NRC staff, in GL 88-01, Supp. 1, to be an acceptable alternative during repair periods of up to 30 days, should be demonstrated to have accuracy comparable to the installed drywell floor and equipment drain sump monitoring system.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

INSERT 2

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

Verification ~~every 31 days~~ that each RHR System cross tie valve on the discharge side of the ~~RHR pumps~~ is closed and power to its operator, if any, is disconnected ensures that each LPCI subsystem remains independent and a failure in the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include de-energizing breaker control power or racking out or removing the breaker. For the valves in high radiation areas, verification may consist of verifying that no work activity was performed in the area of the valve since the last verification was performed. If one of the RHR System cross tie valves is open or power has not been removed from the valve operator, both associated LPCI subsystems must be considered inoperable. ~~The 31 day frequency is acceptable, considering that these valves are under strict administrative controls that will ensure that~~ the valves continue to remain closed with either control or motive power removed.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

Primary containment isolation valves covered by this LCO are listed in the Technical Requirements Manual.

The ACTIONS are modified by a Note allowing isolation valves closed to satisfy ACTION requirements to be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

INSERT 2

Surveillance 4.6.3.4 requires demonstration that a ~~representative sample of~~ reactor instrumentation line excess flow check valves are tested to demonstrate that the valve actuates to check flow on a simulated instrument line break. This surveillance requirement provides assurance that the instrument line EFCV's will perform so that the predicted radiological consequences will not be exceeded during a postulated instrument line break event as evaluated in the UFSAR. ~~The 18-month frequency is based on the need to perform this surveillance under the conditions that apply immediately prior to and during the plant outage and the potential for an unplanned transient if the surveillance were performed with the reactor at power. The representative sample consists of an approximately equal number of EFCV's, such that each EFCV is tested at least once every ten years (nominal). In addition, the EFCV's in the sample are representative of the various plant configurations, models, sizes and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. The nominal 10 year interval is based on performance testing as discussed in NEDO 32977-A, "Excess Check Valve Testing Relaxation." Furthermore, any EFCV failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability is maintained.~~ Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint.

3/4.6.4 VACUUM RELIEF

Suppression Chamber-to-Drywell Vacuum Breakers

BACKGROUND: The function of the suppression-chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are eight internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber that allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test.

If the inoperable suppression chamber-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours and to OPERATIONAL CONDITION 4 within the following 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS: Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. ~~The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.~~

INSERT 2

A Note is added to this SR that allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. ~~The 31-day Frequency of this SR was chosen to provide additional assurance that the vacuum breakers are OPERABLE, since they are located in a harsh environment (the suppression chamber airspace).~~ In addition, this functional test is required within 12 hours after a discharge of steam to the suppression chamber from the safety/relief valves.

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.20 psid is valid. ~~The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. For this facility, the 18-month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.~~

Reactor Building-to-Suppression Chamber Vacuum Breakers

BACKGROUND: The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a check type vacuum relief valve and an air operated butterfly valve located in series) in each of two lines from the reactor building to the suppression chamber airspace. The butterfly valve is actuated by differential pressure. The vacuum breaker is self-actuating and can be remotely operated for testing purposes. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

Action c: With one or more vacuum breaker assemblies with one valve not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable valves must be restored to OPERABLE status or the open vacuum breaker assembly valve closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression-chamber-to-drywell vacuum breakers in LCO 3.6.4.1, "Suppression-Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining valves, the fact that an OPERABLE valve in each of the assemblies is closed, and the low probability of an event occurring that would require the valves to be OPERABLE during this period.

Action d: With one or more vacuum breaker assemblies with two valves not closed, primary containment integrity is not maintained. Therefore, one open valve in each affected assembly must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

If all the valves in a vacuum breaker assembly cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours and to OPERATIONAL CONDITION 4 within the following 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS: Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker position. ~~The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.~~

A Note is added to this SR. The first part of the Note allows reactor-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second part of the Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

INSERT 2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. ~~The 31 day Frequency of this SR is more conservative than the Inservice Testing Program requirements.~~

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.25 psid is valid. ~~The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. For this unit, the 18 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.~~

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Building and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a 0.25 inch water gage vacuum in the reactor building with the filtration recirculation and ventilation system (FRVS) once per 18 months, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during movement of recently irradiated fuel assemblies in the secondary containment or during operations with a potential for draining the reactor vessel (OPDRVs). Due to radioactive decay, handling of fuel only requires OPERABILITY of secondary containment when fuel being handled is recently irradiated, i.e., fuel that has occupied part of the critical reactor core within the previous 24 hours.

During handling of fuel and CORE ALTERATIONS, secondary containment and FRVS actuation is not required. However, building ventilation will be operating during fuel handling and CORE ALTERATIONS and will be capable of drawing air into the building and exhausting through a monitored pathway. To reduce doses even further below that provided by 24 hours of natural decay, a single normal or contingency method to promptly close secondary containment penetrations is provided in accordance with RG 1.183. Such prompt methods need not completely block the penetration or be capable of resisting pressure. The purpose of the "prompt methods" (defined as within 30 minutes) is to enable ventilation systems to draw the release from a postulated fuel handling accident in the proper direction such that it can be treated and monitored. These contingencies are to be utilized after a postulated fuel handling accident has occurred to reduce doses even further below that provided by the natural decay.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment oxygen concentration is maintained less than 4% by volume to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

The primary containment oxygen concentration must be less than 4% by volume when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in OPERATIONAL CONDITION 1, since this is the condition with the highest probability of an event that could produce hydrogen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is less than 15% of RATED THERMAL POWER, the potential for an event that generates significant hydrogen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

If oxygen concentration is ≥ 4% by volume at any time while operating in OPERATIONAL CONDITION 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4% by volume within 24 hours. The 24 hour completion time is allowed when oxygen concentration is ≥ 4% by volume because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

If oxygen concentration cannot be restored to within limits within the required completion time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, plant must be in at least STARTUP within 8 hours. The 8 hour completion time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

The primary containment must be determined to be inert by verifying that oxygen concentration is less than 4% by volume. ~~The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which would lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.~~

INSERT 2

Particulate concentration should be determined in accordance with ASTM D2276, Method A, or ASTM D5452. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. The 0.8 micron filters specified in ASTM D2276 or ASTM D5452 may be replaced with membrane filters up to 3.0 microns. This is acceptable since the closest tolerance fuel filter in the HC EDGs is a five micron particle retention duplex filter on the engine driven fuel oil pump. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. The total volume of stored fuel oil contained in two or more interconnected tanks must be considered and tested separately. The frequency of this test takes into consideration fuel oil degradation trends that indicate the particulate concentration is unlikely to change significantly between frequency intervals.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

With exceptions as noted in the Hope Creek UFSAR, the surveillance requirements for demonstrating the OPERABILITY of the diesel generators comply with the recommendations of Regulatory Guide 1.9, "Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electrical Power Systems at Nuclear Power Plants", Revision 2, December, 1979, Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electrical Power Systems at Nuclear Power Plants", Revision 1, August 1977 and Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators", Revision 1, October 1979 as modified by plant specific analysis, diesel generator manufacturer's recommendations, and Amendment 59, to the Facility Operating License, issued November 22, 1993.

INSERT 2

ATTACHMENT 5

NO SIGNIFICANT HAZARDS CONSIDERATION: LICENSE AMENDMENT TO ADOPT TSTF-425, REVISION 3, "RELOCATE SURVEILLANCE FREQUENCIES TO LICENSEE CONTROL"

Description of Amendment Request: The change requests the adoption of an approved change to the Standard Technical Specifications (STS) for General Electric Plants, BWR/4 (NUREG-1433), to allow relocation of specific TS surveillance frequencies to a licensee-controlled program. The proposed changes are described in Technical Specifications Task Force (TSTF) Traveler, TSTF-425, Revision 3 (ADAMS Accession No. ML090850642) related to the Relocation of Surveillance Frequencies to Licensee Control- RITSTF Initiative 5b and are described in the Notice of Availability published in the Federal Register on July 6, 2009 (74 FR 31996).

The proposed changes are consistent with NRC-approved industry/TSTF Traveler, TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control- RITSTF Initiative 5b." The proposed change relocates surveillance frequencies to a licensee-controlled program, the SFCP. The changes are applicable to licensees using probabilistic risk guidelines contained in NRC-approved NEI 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies," (ADAMS Accession No. 071360456).

Basis for proposed no significant hazards consideration: As required by 10 CFR 50.91(a), the PSEG analysis of the issue of no significant hazards consideration is presented below:

i) Does the proposed change involve a significant increase in the probability or consequences of any accident previously evaluated?

Response: No.

The proposed change relocates the specified frequencies for periodic surveillance requirements to licensee control under a new Surveillance Frequency Control Program. Surveillance frequencies are not an initiator to any accident previously evaluated. As a result, the probability of any accident previously evaluated is not significantly increased. The systems and components required by the Technical Specifications for which the surveillance frequencies are relocated are still required to be operable, meet the acceptance criteria for the surveillance requirements, and be capable of performing any mitigative function assumed in the accident analysis. As a result, the consequences of any accident previously evaluated are not significantly increased.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

ii) Does the proposed change create the possibility of a new or different kind of accident from any previously evaluated?

Response: No.

No new or different accidents result from utilizing the proposed change. The changes do not involve a physical alteration of the plant (i.e. no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. In addition, the changes do not impose any new or different requirements. The changes do not alter assumptions made in the safety analysis. The proposed changes are consistent with the safety analysis assumptions and current plant operating practice.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

iii) Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The design, operation, testing methods, and acceptance criteria for systems, structures, and components (SSCs), specified in applicable codes and standards (or alternatives approved for use by the NRC) will continue to be met as described in the plant licensing basis (including the final safety analysis report and bases to TS), since these are not affected by changes to the surveillance frequencies. Similarly, there is no impact to safety analysis acceptance criteria as described in the plant licensing basis. To evaluate a change in the relocated surveillance frequency, PSEG will perform a probabilistic risk evaluation using the guidance contained in NRC approved NEI 04-10, Rev. 1 in accordance with the TS SFCP. NEI 04-10, Rev. 1, methodology provides reasonable acceptance guidelines and methods for evaluating the risk increase of proposed changes to surveillance frequencies consistent with Regulatory Guide 1.177.

Therefore, the proposed change does not involve a significant reduction in margin of safety.

Based on the above, PSEG concludes the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and accordingly, a finding of "no significant hazards consideration" is justified.