HNP-15-040

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / RENEWED LICENSE NO. NPF-63

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

Enclosure 1

Description and Assessment
(5 pages including cover)

Description and Assessment

1.0 DESCRIPTION

The proposed license amendment would modify Shearon Harris Nuclear Plant (HNP) 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, to TS Section 6, Administrative Controls. The changes are consistent with Nuclear Regulatory Commission (NRC) approved Technical Specification Task Force (TSTF) Standard Technical Specifications (STS) Change TSTF-425, "Relocate Surveillance Frequencies to Licensee Control - RITSTF Initiative 5b," Revision 3 (ADAMS Accession No. ML090850642). The Federal Register notice published on July 6, 2009, announced the availability of this TS improvement.

2.0 ASSESSMENT

2.1 Applicability of Published Safety Evaluation

Duke Energy Progress, Inc. (Duke Energy) has reviewed the safety evaluation dated July 6, 2009 (74 FR 31996). This review included a review of the NRC staff's evaluation, TSTF-425, Revision 3, and the requirements specified in NEI 04–10, Revision 1 (ADAMS Accession No. ML071360456).

Enclosure 2 includes Duke Energy's documentation with regard to Probabilistic Risk Assessment (PRA) technical adequacy consistent with the requirements of Section 4.2 of Regulatory Guide 1.200, Revision 2 (ADAMS Accession No. ML090410014), 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.

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

2.2 Optional Changes and Variations

The proposed amendment is consistent with the STS changes described in TSTF-425, Revision 3, but Duke Energy proposes variations or deviations from TSTF-425, as identified below, and also includes differing TS Surveillance numbers:

- Revised (clean) TS pages are not included in this amendment request given the number of TS pages affected, the straightforward nature of the proposed changes, and outstanding license amendment requests that may affect some of the same TS pages. Providing only markups of the proposed TS changes satisfies the requirements of 10 CFR 50.90, "Application for Amendment of License, Construction Permit, or Early Site Permit," in that the markups fully describe the changes desired. This is an administrative

deviation from the NRC staff's model application dated July 6, 2009 (74 FR 31996), with no impact on 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.

- The definition of STAGGERED TEST BASIS is being retained in HNP TS Definition Section 1.0 because this terminology is used in Administrative TS Section 6.8.4.o, "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).

- The TSTF-425 insert for each relocated surveillance frequency is changed from "in accordance with the Surveillance Frequency Control Program" to read "at the frequency specified in the Surveillance Frequency Control Program."

  The insert provided in TSTF-425 to replace text describing the basis for each frequency relocated to the Surveillance Frequency Control Program (SFCP) has been revised from "The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program" to read "The surveillance frequency is controlled under the Surveillance Frequency Control Program." After NRC approval of the license amendment request (LAR), and as part of the LAR implementation, the existing HNP Bases information describing the basis for the relocated surveillance frequencies will also be relocated to a licensee controlled program with the relocated surveillance frequencies.

  In addition, other editorial changes to the existing TS wording and/or text inserts are being made. These administrative/editorial deviations to the TSTF-425 inserts and the existing TS wording are made to fit the HNP TS format.

- Enclosure 6 provides a cross-reference between NUREG-1431 "Standard Technical Specifications – Westinghouse Plants," surveillances included in TSTF-425 and HNP surveillances included in this amendment request. This cross-reference highlights the following:
  - NUREG-1431 surveillances included in TSTF-425 and corresponding HNP surveillances with plant-specific surveillance numbers
  - HNP plant-specific surveillances that are not contained in NUREG-1431 and therefore are not included in the TSTF-425 markups but are included in this submittal.

  For NUREG-1431 surveillances not contained in HNP TSs, the corresponding markups identified in TSTF-425 for these surveillances are not applicable. 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).

  Concerning the second bullet above, the HNP TSs are based upon the format and content of the NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," series. As a result, the HNP TS surveillance numbers and

associated Bases numbers differ from the surveillance numbers and Bases numbers in NUREG-1431, "Standard Technical Specifications – Westinghouse Plants," as shown in TSTF-425, Revision 3. In addition, the Administrative Controls Section TS is Section 6.0 for HNP verses Section 5.0 for NUREG-1431. These differences are administrative deviations from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

For HNP plant-specific surveillances not included in the NUREG-1431 markups provided in TSTF-425, Duke Energy has determined that since these surveillances involve fixed periodic frequencies, relocation of these frequencies is consistent with TSTF-425, Revision 3, and with the NRC model safety evaluation dated July 6, 2009 (74 FR 31996), including the scope exclusions identified in Section 1.0, "Introduction," of the model safety evaluation. In accordance with TSTF-425, changes to the frequencies for these surveillances would be controlled under the SFCP.

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration

Duke Energy has reviewed the proposed no significant hazards consideration (NSHC) determination published in the Federal Register on July 6, 2009 (74 FR 31996) and has concluded that the proposed NSHC presented in the Federal Register notice is applicable to HNP. As such, the NSHC determination for this amendment request is provided as Attachment 5 to this license amendment request 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, and the NRC's model safety evaluation published in the Notice of Availability dated July 6, 2009 (74 FR 31996). Duke Energy has concluded that the relationship of the proposed changes to the applicable regulatory requirements presented in the Federal Register notice is applicable to HNP.

3.3 Precedent

The proposed relocation of surveillance frequencies is similar to License Amendment No. 258 issued to Millstone Power Station, Unit 3, on February 25, 2014 (ADAMS ML14023A748) and License Amendment No. 263/258 issued to Turkey Point Nuclear Generating Unit Nos. 3 and 4, on July 16, 2015 (ADAMS ML15166A320).

3.4 Conclusions

In conclusion, based on the considerations discussed above, (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

Duke Energy 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). Duke Energy has concluded that the staff's findings presented therein are applicable to HNP, and the determination is hereby incorporated by reference for this application.

5.0 REFERENCES

1. TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – RITSTF Initiative 5b," March 18, 2009 (ADAMS Accession No: ML090850642)

2. NRC Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk-Informed Technical Specification Task Force (RITSTF) Initiative 5b, Technical Specification Task Force – 425, Revision 3, published on July 6, 2009 (74 FR 31996)

3. Regulatory Guide 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009 (ADAMS Accession No. ML090410014)

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Enclosure 2

Documentation of Probabilistic Risk Assessment (PRA) Technical Adequacy
(29 pages)

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Shearon Harris Nuclear Power Plant, Unit 1
Docket No.50-400/Renewed License No. NPF-63

Application for Technical Specification Change Regarding Risk-Informed Justification for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program

Documentation of Probabilistic Risk Assessment (PRA) Technical Adequacy

1.0 OVERVIEW

Shearon Harris Nuclear Power Plant, Unit No.1 (HNP) will follow the methodology provided in NEI 04-10, Revision 1 (Reference 1), to develop a risk informed Surveillance Frequency Control Program (SFCP) for control of Technical Specification surveillance frequencies. NEI 04-10 provides guidance for implementation of a generic Technical Specifications improvement that establishes licensee control of surveillance test frequencies for the majority of Technical Specifications surveillances. Existing specific surveillance frequencies will be removed from Technical Specifications for the affected specifications, and placed under licensee control pursuant to this methodology.

The NEI 04-10 methodology uses a risk-informed, performance-based approach for establishment of surveillance frequencies and is consistent with the philosophy of NRC Regulatory Guide 1.174 (Reference 2). Probabilistic Risk Assessment (PRA) methods will be used to determine the risk impact of the revised intervals. PRA technical adequacy has been addressed through NRC Regulatory Guide 1.200, Revision 2 (Reference 3), which references the ASME/ANS PRA, RA-Sa-2009 (Reference 4), for internal events at power. External events and shutdown risk impact will be considered quantitatively or qualitatively as described herein.

This enclosure demonstrates the technical adequacy of the HNP PRA model to be used as the basis for the HNP SFCP, consistent with the requirements of Section 3.3 and Section 4.2 of RG 1.200, Revision 2 (Reference 3):

- Section 2.0 addresses the need for the PRA model to represent the as-built, as-operated plant,

- Section 3.0 discusses permanent plant changes that have an impact on those things modeled in the PRA but have not been incorporated in the baseline PRA model.

- Section 4.0 demonstrates that the various technical elements of the HNP PRA have been performed consistently with the ASME/ANS PRA Standard as endorsed in the appendices of RG 1.200. The peer reviews that have been conducted and the resolution of findings from those reviews are included in this section. These demonstrate that the pieces of the PRA have been performed in a technically correct manner.

- Section 5.0 includes a summary of the methodology that will be used to assess the risk under the SFCP.

- Section 6.0 identifies the key assumptions and approximations relevant to the results used in the decision-making process. This section provides assurance that the assumptions and approximations used in development of the PRA are appropriate.

- The resolution of the peer review findings and observations (F&Os) for the HNP PRA is discussed in section 4.0, and resolutions for the Internal Flooding PRA (IFPRA) F&Os are provided in Table 1.

- Demonstration from peer reviews that the PRA meets the requirements of the ASME/ANS PRA Standard at appropriate capability categories is discussed in Section 4.0.

2.0 BASIS TO CONCLUDE THAT THE PRA MODEL REPRESENTS THE AS-BUILT, AS-OPERATED PLANT

The HNP PRA Model of Record (MOR) is maintained as a controlled document and is updated on a periodic basis to represent the as-built, as-operated plant. Duke Energy procedures provide the guidance, requirements, and processes for the maintenance, update, and upgrade of the PRA:

a. The process includes a review of plant changes, selected plant procedures, and plant operating data as required, through a chosen freeze date to assess the effect on the PRA model.

b The PRA model and controlling documents are revised as necessary to incorporate those changes determined to impact the model.

c The determination of the extent of model changes includes the following:

  - Accepted industry PRA practices, ground rules, and assumptions consistent with those employed in the ASME/ANS PRA Standard (Reference 4),
  - Current industry practices,
  - NRC guidance (e.g., References 2-3),
  - Advances in PRA technology and methodology, and
  - Changes in external hazard conditions.

For plant changes of small or negligible impact, the model changes can be accumulated and a single revision is performed at an interval consistent with major PRA revisions. The results of each evaluation determine the necessity and timing of incorporation of a particular change into the PRA model. An electronic tracking database is utilized to document pending model changes and updates.

3.0 IDENTIFICATION OF PERMANENT PLANT CHANGES NOT INCORPORATED IN THE PRA MODEL

The HNP Model of Record (MOR2010) is based on the plant configuration as of May 31, 2010, including Refueling Outage 16 modifications and plant-specific data through May 2006. The HNP PRA Working Model used for risk-based applications is the effective PRA MOR that has incorporated some or all changes made in plant design, procedure revisions, and data identified in the PRA Tracker since the PRA MOR freeze date. All permanent plant modifications and ECs that have been implemented since MOR2010 have been reviewed (through the HNP 2015 Outage) and included in the PRA working model as appropriate. The HNP fire PRA and internal flooding PRA were updated in 2013 and 2014, respectively. There are currently no identified permanent plant modifications that have a significant impact on the PRA that have not been incorporated into the MOR.

4.0 CONFORMANCE WITH ASME/ANS PRA STANDARD

The following sections describe the conformance and capability of the HNP PRA against the ASME/ANS PRA Standard (Reference 4).

4.1 Internal Events PRA

The following peer reviews have been conducted to ensure the internal events PRA meets the requirements of ASME/ANS PRA Standard:

- In 2002, a peer review was performed by Westinghouse Owners Group (WOG) in accordance with guidance in NEI-00-02, Industry PRA Peer Review Process. All of the F&Os were resolved.
- In 2006, a self-assessment was conducted to identify supporting requirements that did not meet Category II of the ASME Standard RA-Sb-2005 and RG 1.200, Rev. 1. The significance of the F&Os was determined with regard to whether the issue may adversely impact the effective use of the PRA in risk-informed applications. All significant technical findings were reviewed and resolved.
- In 2007, a focused industry peer review was conducted as a follow up to the self-assessment against AMSE Standard RA-Sb-2005 and RG 1.200, Rev. 1. All findings recorded from that review have been resolved.
- In 2008, two internal events F&Os were identified during an NRC staff review of the HNP fire PRA model. These findings were reviewed and resolved.

In reviewing the HNP risk informed License Amendment Request (LAR) for implementation of NFPA 805, the NRC staff evaluated the quality of the internal events PRA model used to support development of the Fire PRA. The objective of the quality review was, "to determine whether the plant-specific PRA used in evaluating the proposed LAR is of sufficient scope, level of detail, and technical adequacy for the application." The results of the NRC staff quality review are documented in the HNP NFPA 805 Safety Evaluation for transition to a risk-informed, performance-based fire protection program, ADAMS Accession Numbers ML101750602 and ML101750604 (References 5-6).

As part of the quality review, the NRC staff reviewed the F&O responses from each of the internal events peer reviews and determined that all but one of the dispositions were acceptable. The staff considered F&O DA-C1-01, in which the licensee used a value of 0.33 for generic data sources with zero failures, to not be dispositioned adequately. However, the NRC staff concluded that the use of a more accepted value in these circumstances would not impact the conclusions drawn from the results associated with this application. Accordingly, considering the minimal impact reasonably expected from changes to the PRA associated with addressing this single item, the staff concluded that the licensee has demonstrated that the internal events PRA model is technically adequate to support the NFPA 805 risk calculations necessary for the license amendment.

Based on these reviews, the HNP internal events PRA meets the requirements of the ASME/ANS PRA Standard as endorsed by RG 1.200, Revision 2, at an appropriate capability category to support the HNP Surveillance Frequency Control Program (SFCP). The internal events PRA will be used in accordance with NEI 04-10 to assess proposed surveillance frequency changes under the SFCP.

4.2 Fire PRA

The HNP fire PRA was developed using the guidance provided by NUREG/CR-6850 (Reference 7) in support of NFPA 805 fire protection program, and HNP was a pilot plant for implementation of NFPA 805. The fire PRA is built upon the internal events PRA which was modified to capture the effects of fire. In 2008, both a follow-up, partial-scope industry peer review and an NRC staff review were conducted on the fire PRA. The follow-up industry peer review compared the fire PRA against the requirements of the ANSI/ANS 58.23-2007 standard (Reference 8) in accordance with guidance in NEI 07-12, Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines (Reference 9). All findings have been reviewed and resolved, and the resolutions were submitted as part of the NFPA 805 LAR. The results of the NRC staff quality review of the Fire PRA are documented in the HNP NFPA 805 Safety Evaluation for transition to a risk-informed, performance-based fire protection program, ADAMS Accession Numbers ML101750602 and ML101750604 (References 5-6). The quality review concluded that the technical adequacy and quality of the HNP PRA is sufficient for the fire risk evaluations that support NFPA 805 fire protection program.

It should be noted that during the course of the review of the HNP NFPA 805 LAR, several of the [listed] guidance documents were revised to incorporate updated information and lessons learned from the pilot process. As such, the original HNP NFPA 805 LAR was submitted against earlier revisions of some of these documents (e.g., RG 1.205). However, as the LAR was supplemented by various letters, many of the positions in the new document revisions were incorporated into the application. Accordingly, the NRC staff considers that the NFPA 805 LAR meets the intent of the current document revisions, and was reviewed as such.

Based on these reviews, the HNP fire PRA meets the requirements of the ASME/ANS PRA Standard at an appropriate capability category to support the HNP SFCP. The fire PRA will be used in accordance with NEI 04-10 to assess proposed surveillance frequency changes under the SFCP.

4.3 Internal Flooding PRA

The internal flooding portion of the HNP PRA was updated in 2014 in order to meet the requirements of the ASME/ANS PRA Standard and RG 1.200, Rev. 2. A focused peer review of the IFPRA was conducted following the guidance of NEI 05-04 (Reference 10) to assess the model against the supporting requirements of the ASME/ANS PRA standard. All F&Os from the peer review have been resolved, and the resolutions for the IFPRA findings are presented in Table 1 of this attachment.

Based on the results and resolution of the findings from the focused peer review, the HNP internal flooding PRA meets the requirements of the ASME/ANS PRA Standard and RG 1.200, Rev. 2, at an appropriate capability category to support the evaluation of proposed surveillance frequency changes. The internal flooding PRA will be used in accordance with NEI 04-10 to assess proposed surveillance frequency changes under the SFCP.

4.4 External Events and Shutdown Risk

The following sections describe how external events and shutdown risk are evaluated.

4.4.1 Seismic

For the IPEEE submitted in 1995, HNP employed EPRI's Seismic Margins Analysis (0.3g Review Level Earthquake) to identify vulnerabilities to seismic events. In 2014, HNP completed a Seismic Hazard Evaluation and Screening Report in response to NRC 10 CFR

50.54(f) regarding recommendations of the Near-Term Task Force (NTTF) review of insights from the Fukushima Dai-ichi accident. The results indicate the updated seismic hazard is lower than evaluated in the IPEEE and is not a significant hazard requiring quantitative risk evaluation. SSCs impacted by frequency changes under the SFCP, therefore, will be assessed against the seismic margins analysis and evaluated in accordance with NEI 04-10.

4.4.2 External Flooding

For the IPEEE submitted in 1995, HNP utilized a screening approach described in NUREG-1407 to identify potential vulnerabilities due to external floods. In 2013, HNP completed a Flood Hazard Reevaluation Report in response to NRC 10 CFR 50.54(f) regarding recommendations of the NTTF review of insights from the Fukushima Dai-ichi accident. The results indicate that some flood levels determined during the hazard reevaluation exceed the Current Licensing Basis (CLB) flood levels. The increased levels are the result of newer methodologies and not the result of errors within the CLB evaluations. The increased levels do not exceed the flood protection capabilities and do not impact safety-related equipment, thus do not require a quantitative risk evaluation. SSCs impacted by frequency changes under the SFCP, therefore, will be assessed against the IPEEE analysis and evaluated in accordance with NEI 04-10.

4.4.3 High Winds

For the IPEEE submitted in 1995, HNP concluded that SSCs whose failure could prevent safe shutdown of the reactor [due to design wind loading, tornado wind loading, or associated missiles] are protected from such failure by either being designed to withstand such loading or being housed within a structure which is designed to withstand the loading. High winds, therefore, are not considered a significant hazard at HNP and do not require a quantitative risk evaluation. SSCs impacted by frequency changes under the SFCP, therefore, will be assessed against the IPEEE analysis and evaluated in accordance with NEI 04-10.

4.4.4 Transportation and Nearby Facility Accidents

For the IPEEE submitted in 1995, HNP concluded that potential accidents associated with nearby air traffic, runways, roads, railways and fixed facilities are not considered a significant hazard and do not require a quantitative risk evaluation. SSCs impacted by frequency changes under the SFCP, therefore, will be assessed against the IPEEE analysis and evaluated in accordance with NEI 04-10.

4.4.5 Shutdown Risk

HNP operates under a shutdown risk management program to support implementation of NUMARC 91-06 (Reference 11). Technical Specifications and safety risk management guidelines are used to manage risk during Mode 4. For Modes 5, 6, and defueled, the shutdown risk management implementing procedures provide guidelines for outage risk management which meet or exceed Technical Specifications. HNP will use the shutdown risk management program procedures to assess shutdown risk for proposed surveillance frequency changes.

4.4.6 Conclusions on External Events and Shutdown Risk

External hazards screenings have been performed for HNP to support requirements of the IPEEE and in review of insights from the Fukushima Dai-ichi accident. NEI 04-10 allows for proposed surveillance frequency change evaluations to use hazard screening in the absence of external hazards PRA models. In cases where these methodologies are not appropriate for a surveillance frequency change evaluation, other qualitative or bounding analysis can be

utilized to provide justification for the acceptability of the proposed surveillance frequency change. HNP will follow the NEI 04-10 guidance to assess external event and shutdown risk associated with potential surveillance frequency changes.

5.0 METHODOLOGY TO BE USED TO ASSESS SURVEILLANCE FREQUENCY CHANGES

Existing Duke Energy procedures derived from the NEI 04-10 guidance will be used to govern the SFCP and the surveillance test interval (STI) evaluation process. The following steps will be used to assess proposed changes within the HNP program.

- Each STI revision will be 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 will proceed. If a commitment exists and the commitment change process does not permit the change, then the STI revision will not be implemented. Only after receiving formal NRC approval to change the commitment will an STI revision proceed.

- Systems engineering evaluations and quantitative assessments from available PRA models will be developed for each proposed change. The HNP internal events, internal flooding and fire PRAs all meet the requirements for RG 1.200, Rev. 2, and will be used to assess whether an SSC is affected by the proposed STI change. In calculating SSC failure rates, if the breakdown between the standby time-dependent failure rate and the demand-related failure rate probability for affected SSCs is unknown, then the total failure probability will be assumed to be time-related to obtain the maximum test-limited risk condition. The total and cumulative effects on CDF and LERF will be assessed, and cumulative risk will be tracked.

- If an SSC being assessed is not modeled in the PRA, then appropriate qualitative or bounding risk analysis will be performed for that SSC. Duke Energy procedures derived from NEI guidelines will be used to determine if the qualitative analysis is sufficient for consideration.

- Hazard screening performed for the IPEEE, and review of programmatic assessments performed in response to the Fukushima Dai-ichi accident will be used to assess seismic and other external events (external flood, high winds, transportation and nearby facilities) for potential changes in STI. The HNP shutdown risk management program for implementation of NUMARC 91-06 will be used to assess the shutdown risk.

- The results of each STI assessment will be documented and presented to an Expert Panel, referred to as the Integrated Decision-making Panel (IDP). The IDP will normally be the same panel used for Maintenance Rule implementation but with the addition of specialists with experience in surveillance testing and system or component reliability. If the IDP approves the STI revision, the change will be documented and implemented, and will be available for audit by the Nuclear Regulatory Commission (NRC). If the IDP does not approve the STI revision, the surveillance frequency is left unchanged.

- Performance monitoring will be conducted as recommended by the IDP. In some cases, no additional monitoring may be necessary beyond that already conducted under the Maintenance Rule. Performance monitoring helps to confirm that no failure mechanisms

related to the revised STI 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 reset the STI to the previously acceptable test interval.

6.0 KEY ASSUMPTIONS AND APPROXIMATIONS

A list of potential contributors to the uncertainty in the PRA was compiled. The list below represents the modeling assumptions and uncertainty that are considered to have the greatest impact on the HNP PRA results if different reasonable alternative assumptions were utilized. The approaches taken for the assumptions below represent industry best practices and therefore the need for sensitivity analyses will be determined separately for each of the individual surveillance frequency changes evaluated.

6.1 Reactor Coolant Pump (RCP) Seal Failure

The HNP PRA model uses the WOG 2000 RCP seal failure model, and it assumes RCP seal leakage every time both Seal Injection and Thermal Barrier cooling are lost. This is an Industry consensus model. For risk applications this is one of the most important areas of uncertainty.

6.2 Loss of Off-Site Power (LOOP) Frequencies

Loss of off-site power initiating events have been shown to be important contributors to plant core damage due to the potential for station blackout and the reliance of many frontline systems on AC power. The LOOP initiator was separated into plant, grid, switchyard and weather induced LOOPs, which allowed the model to apply recovery actions to the higher frequency events (plant and switchyard). HNP used generic industry data to calculate LOOP frequencies. The LOOP frequency has a significant impact on CDF and Emergency Diesel Generator (EDG) importance.

6.3 Fire Modeling

Fire modeling, although following the technical guidance of NUREG-6850, contains several risk important elements that are judged to contain large uncertainties for their respective elements of fire risk methodology. These elements include the fire ignition frequency, heat release rates, fire growth curves, fire suppression failure probabilities, severity factors, and post-initiator human failure event probabilities. While the approaches taken in the HNP Fire PRA represent the "state of the art" methodology, they are still constrained by the relatively limited data on fire events at Nuclear Power Plants. As part of the NRC quality review of the HNP Fire PRA, the NRC staff reviewed the fire modeling performed and found the application of each of the correlations used in the model to be acceptable to support transition to NFPA 805.

7.0 CONCLUSIONS ON PRA TECHNICAL ADEQUACY

The Harris Nuclear Plant (HNP) PRA model is sufficiently robust and suitable for use in risk informed processes such as the Surveillance Frequency Control Program. The peer reviews that have been conducted and the resolution of findings from those reviews demonstrate that the pieces of the PRA have been performed in a technically correct manner. The assumptions and approximations used in development of the PRA have also been reviewed and are

appropriate for their application. Duke Energy procedures are in place for controlling and updating the models, when appropriate, and for assuring that the model represents the as-built, as-operated plant. The conclusion, therefore, is that the HNP PRA model is acceptable to be used as the basis for risk-informed applications such as Risk-Informed Technical Specifications (RITS) Initiative 5b.

8.0 REFERENCES

1. NEI 04-10, "*Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies*," Revision 1, April 2007.
2. Regulatory Guide 1.174, "*An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*," Revision 2, U.S. Nuclear Regulatory Commission, March 2011.
3. Regulatory Guide 1.200, "*An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk- Informed Activities*," Revision 2, U.S. Nuclear Regulatory Commission, March 2009.
4. ASME/ANS RA-Sa-2009, "*Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,*" Addendum A to RA-S-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.
5. Letter from the NRC to C. Burton, "*Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment Regarding Adoption of National Fire Protection Association Standard 805, 'Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants'*," June 28, 2010. (ADAMS Accession No. ML101750602)
6. "*Safety Evaluation By The Office Of Nuclear Reactor Regulation Related To Amendment No. 133 To Renewed Facility Operating License No. NPF-63, Transition To A Risk-Informed, Performance-Based Fire Protection Program In Accordance with 10 CFR 50.48(c),*" Shearon Harris Nuclear Power Plant, Unit 1, Docket No. 50-400, U.S. Nuclear Regulatory Commission, Washington, D.C., June 28, 2010. (ADAMS Accession No. ML101750604)
7. NUREG/CR-6850, "*EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities*," Volume 2, September, 2005.
8. ANSI/ANS 58.23-2007, "Fire PRA Methodology," American Nuclear Society, November 2007.
9. NEI 07-12, Draft Version E, "*Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines*," Nuclear Energy Institute, May 2007.
10. NEI 05-04, "*Process for Performing Follow-On PRA Peer Reviews Using the ASME PRA Standard (Internal Events)*," Revision 1 (Draft), Nuclear Energy Institute, November 2007.
11. NUMARC 91-06, "*Guidelines for Industry Actions to Address Shutdown Management*," December 1991.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
1-1	No characterization of the potential impact of assumptions or sources of model uncertainty, which is usually performed as described in NUREG-1855, was performed. Characterization of the assumptions and sources of model uncertainty is required by SR IFPP-B3	All HNP internal flooding calculations were revised to include a table of the listed assumptions of the individual calculation. This newly added table provides a description of the assumption, and a determination as to whether the uncertainty is considered aleatory or epistemic based on NUREG-1855. The table also includes the basis of this determination and an estimation as to how much impact on the model this assumption and resultant uncertainty is expected contribute. The revisions to the HNP internal flooding calculations documents the assessment and characterization of model uncertainty and assumptions per NUREG-1855 as suggested by the peer review team. Impacted calculations include: • HNP-F/PSA-0090 • HNP-F/PSA-0091 • HNP-F/PSA-0092 • HNP-F/PSA-0093 • HNP-F/PSA-0094	Resolution of this F&O required an update of the IFPRA documentation but did not result in any changes to the PRA model. The impacted calculations have been updated. No further analysis is required for the 5b application.
1-2	Assumption 5-15 of HNP-F-PSA-0091 states, "Insulated pipes are not considered spray sources in that a potential leak will not spray but will instead be shielded by the insulation and will, therefore, drip instead." Similar assumptions are made in assumptions 7 and 8 of HNP-F-PSA-0092 and 2.3.8 and 2.3.9 of HNP-F-PSA-0090. This assumption is not supported by engineering evaluations. Spray events could occur from pipe breaks that release up to 100 gpm. It is considered incredible that pipe	The analysis has been modified so that drips from insulated piping have been treated as if they were spray scenarios from bare piping. In addition, the effects of sprays and other flooding mechanisms (e.g., dripping, splashing, or channeling) have been reassessed, and scenarios have been modified as appropriate on a compartment-by-compartment basis as described in F&O 1-3 and the walkdown calculation. Susceptibility of SSCs to spray was noted on walkdown sheets.	Resolution of this F&O has been incorporated into the sequence analysis for the IFPRA, and spray scenarios were reassessed accordingly. No further analysis is

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	insulation could prevent such breaks from resulting in spray. Furthermore, no analysis of where the fluid could propagate is provided if the insulation prevents spray.		required for the 5b application.
1-3	Assumption 5-15 of HNP-F-PSA-0091 states, "PRA-related SSCs are considered to be susceptible to the effects of spray if they are within 20 feet of an unobstructed potential spray source. This 20-foot radius is applied along the entire length of pipe in the flood compartment since it is not possible to predict where in the pipe system that a leak/break will occur." Similar assumptions are made in assumptions 6 of HNP-F-PSA-0092 and 2.3.6 of HNP-F-PSA 0090. This assumption is not supported by engineering evaluations. Furthermore, potential effects of splash, dripping, or flow along cable trays or other structures appears not to have been considered. Neglecting these other flooding effects, required per RG 1.200, could omit flood scenarios.	Assumption 5-14 (rather than 5-15) was not supported by appropriately by engineering evaluations. The effects of sprays and other flooding mechanisms (e.g., dripping, splashing, or channeling) have been reassessed, and scenarios have been modified as appropriate on a compartment-by-compartment basis. Details of how scenarios were assessed are provided in this response and documented in the noted calculations. For small flood compartments (FLCs), all susceptible PRA-related equipment in the compartment is assumed to fail as a result of a spray event (per the suggested resolution). The Harris Nuclear Plant (HNP), however, has several large rooms/hallways where failure of all equipment due to spray is neither practical nor realistic and would significantly over estimate the core damage frequency from a spray event. Arbitrary definition of smaller flood compartments in large areas where no barriers exist is not realistic and is not compliant with the PRA Standard (IFPP-A1 and IFPP-A2). The assessment of the effects of sprays, therefore, assumes that only equipment within a zone of influence (ZOI) of the break/spray location will be affected. The zone of influence (ZOI) is defined as the volume about the break in which the fluid escaping from the break can cause equipment failure within the zone. For this assessment, it is assumed that the ZOI for sprays from moderate and low energy pipe breaks is bounded by the ZOI for sprays resulting	All identified spray scenarios have been reassessed accordingly, and resolution of this F&O has been incorporated into the IFPRA documentation. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
		from jet impingement evaluation of a high energy line break (HELB) as described in NUREG/CR-2913, dated January 1983. Components impacted by jets from breaks in piping containing high-pressure (870 to 2466 psia) steam or sub-cooled liquid that would flash at the break are evaluated as follows: 1. Impacted components within 10 inside diameters (10D) of the broken pipe are assumed to fail. 2. Components beyond 10 inside diameters of the broken pipe are considered to be undamaged by the jet/spray. For the HNP IFPRA, therefore, it is assumed that the radius for the spray/HELB zone of interest is 20 feet for a break in any pipe with and inside diameter less than or equal to 24-inches. For larger pipes (greater than 24-inches), the radius of the zone of interest is assumed to be 10D. The use of jet impingement evaluations has been previously reviewed and approved by the NRC. Drips from insulated piping have been treated as if they were spray scenarios from bare piping. Channeling of fluid through ducts and cable trays, and splashing of equipment have been reassessed and treated as a spray/flood event, where applicable, based on additional plant walkdowns. An additional appendix describing potential propagation through ducts has been added to HNP-F/PSA-0091. Any spray susceptible SSCs that were noted to fall into this category was to be flagged on the walkdown sheet as being potentially affected by spray and the damage set modified accordingly in the scenario development calculation.	

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review

F&O #	Finding	Resolution	5b Impact
1-4	Assumption 5-12 of HNP-F-PSA-0091 states, "Any pressure boundary failures or inadvertent equipment actuation resulting in the release of fuel oils, lubricating oils, or electro-hydraulic control (EHC) fluids are not included. These types of events typically result in localized spraying of adjacent equipment, sometimes with a resulting fires that are addressed within the scope of the fire PRA." This assumption is not supported by engineering evaluations. Furthermore, RG 1.200 requires that the potential flood effect of all fluids, including oils, fuels, etc., be evaluated.	Table 6-6 lists all non-water liquid systems, but their screening determinations have been revised. These new screening determinations in Table 6-6 are now supported by Attachment 7 of HNP-F/PSA-0091. Table 1 in Attachment 7 contains the necessary specifications to support the screening of the listed miscellaneous systems. Main focus was the location and capacity of the system, system pressure and temperature, and flow rate to support the determination of spray, HELB, and flood events. Attachment 7 also provides the justification for excluding several systems from both the screening decision and from Table 1 altogether. Table 6-6 was updated and is maintained in HNP-F/PSA-0091 with a reference to Attachment 7. Final note is to clarify the assumption in question, in this case, it's assumption 5-2 of HNP-F/PSA-0091, not 5-12.	All non-water liquid systems have been incorporated into the IFPRA and scenarios have been screened per the Standard with the resolution of this F&O. No further analysis is required for the 5b application.
1-5	Assumption 5-12 of HNP-F-PSA-0091 states, "Motor operated valves are assumed to fail in their "as-is" position when submerged. It is further assumed that MOV's do not fail due to spray based equipment testing done for the Brunswick Nuclear Plant (BNP). Engineering Change EC-93443 provides analysis and testing of the effects of water on MOV's. Submergence testing of valve actuators demonstrated that minor in-leakage into the valve was observed, but not to the extent that a flooding induced fault of the DC controls would occur. Based on this evaluation, it is assumed that MOV's are not subject to	Used three methods to support the assumption that all PRA-related MOVs at HNP will operate as designed during and after being subjected to a liquid spray event. First method was to address the assumption of there being a correlation between the MOV tested at BNP and all the MOVs used at HNP. Due to the large variation of MOVs used at HNP, this correlation did not apply to all MOVs, since we did not use the Environmental Qualification program to link other models to the tested models. Remaining models were then covered by using the Environmental Qualification program to list the MOVs that are maintained under this program, giving them the classification to survive a liquid spray event. Finally, used vendor manuals with NEMA classifications to determine in what environments these MOVs are designed to withstand and operate correctly.	The IFPRA documentation was updated with analysis to validate the assumptions used to assess the impact of spray on the identified equipment. Resolution of this F&O did not result in any changes to the IFPRA model. No

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	failure due to spray since sprays do not have the same driving head as submergence for water penetration." Similar assumptions are made in assumptions 3 of HNP-F-PSA-0092 and 2.3.4 of HNP-F-PSA-0090. There is no documentation that the testing performed for the BNP valves is applicable to the valves at HNP.	Attachment 8 was added to HNP-F/PSA-0091 and presents our findings from these three methods and concludes that all PRA-related MOVs at HNP will operate as designed during and after a liquid spray event.	further analysis is required for the 5b application.
1-6	Assumption 5-18 of HNP-F-PSA-0091 states, "The miscellaneous fluid systems shown in Table 6-6 are of limited capacity and are not expected to cause significant flooding events that result in flood-induced failures of PRA-related components due to submergence." The ability of systems to submerge components must be evaluated uniquely for each flood area and consider the volume of the area affected along with other potential effects such as temperature, humidity, steam and actuation of fire protection systems.	The screening determinations in Table 6-6 are now supported by Attachment 7 of HNP-F/PSA-0091. Table 1 in Attachment 7 contains the necessary specifications to support the screening of the listed miscellaneous systems. Main focus was the location and capacity of the system, system pressure and temperature, and flow rate to support the determination of spray, HELB, and flood events. Attachment 7 also discusses why several systems were excluded from Table 1 and excluded from the screening decision. Table 6-6 was updated and is maintained in HNP-F/PSA-0091 with a reference to Attachment 7.	The misc. systems analysis was updated, and the F&O was resolved per the Standard. Updates were incorporated appropriately into the IFPRA scenario analysis. No further analysis is required for the 5b application.
1-7	Flood alarms are identified in the HRA analyses presented in Table 7-2 of HNP-F-PSA-0094. However, the alarms are not specifically identified nor the alarms correlated to the flood source that causes the flooding event. Identification of alarms that are	Per the suggested resolution an additional column has been added to Table 7-2 of HNP-F/PSA-0094 in order to list the specific alarms that might be available to indicate floods or leaks in the compartment. Table 7-2 was revised to list the specific alarms or indications of leaks or flooding per compartment as well as the specific alarms to aid in flood identification in the area.	The HRA analysis was updated to include specific alarms per the recommended resolution. No

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	expected for each flood source that could release fluid in each area is required by the SR.		further analysis is required for the 5b application.
1-8	Sump pumps and sumps generally are not identified. Identification of sumps and sump pumps is required by the SR	The HNP sumps and sump pump locations, along with all relevant information are now documented in Attachment 6 of HNP-F/PSA-0091, Revision 1. This is the Areas and Sources calculation for HNP Internal Flooding. Documentation of their walk down results are located in the Walkdown Calculation as well (HNP-F/PSA-0090 Rev. 1).	The sump information was assessed in the propagation analysis per the Standard. No further analysis is required for the 5b application.
1-9	Flow through floor drains is calculated and documented in Table 6-9 of HNP-F-PSA-0091. However, it appears that flow is incorrectly calculated for situations when multiple floor drains are connected to a common drain line. The calculations shown in HNP-F-PSA-0091 show a capacity per floor drain and the total capacity in each flood area is the average capacity per drain multiplied by the number of floor drains. However, no discussion of how multiple drains are connected to common drain lines is provided. When multiple drains flow through a common drain line, the flow	All floor drains above the 190' elevation drain to the Floor Drain Transfer Tank (FDTT) on the 190' level through a series of common drain pipes and risers. The total capacity of the drains for a particular flood compartment will be limited by the common drain line/riser for that compartment, so the drain flow calculations have been revised. The locations of the floor drains, drain lines, and risers are shown in the revised Attachment 4 of HNP-F/PSA-0091. The equations used to re-calculate drain flow are provided, and a calculation of flow through a typical series of floor drains connected to a common drain line has been performed. The revised drain flow calculation demonstrated that the common drain line/riser has excess capacity to remove water	The IFPRA documentation was updated with analysis to validate the assumptions used to assess the impact of the floor drains. Resolution of this issue did not result in any changes to the PRA

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	from each successive drain greatly reduces the flow from each drain in the system.	from multiple floor drains for spray scenarios (<100 gpm) in a given flood compartment. The common drain line, however, does not have sufficient capacity to provide beneficial removal of water for larger flood scenarios. This conclusion about capacity from the "typical" model is applicable to all flood compartments, so detailed modeling by flood compartment of multiple, similar configurations of a complex drain system was not performed. IFSN-A4 says to, "ESTIMATE the capacity of the drains...[and] ACCOUNT for these factors in estimating flood volumes and SSC impacts from flooding." The capacity of the drains has been estimated and their ability to mitigate flood effects has been included in the scenarios, where applicable, thus satisfying this F&O. The propagation analysis documented in HNP-F/PSA-0092 includes removal of water by the floor drains for spray scenarios but does not credit removal of water by the floor drains for other scenarios. Section 6.3.3 and Attachment A of HNP-F-PSA-0091 have been updated accordingly to include the revised analysis.	model. No further analysis is required for the 5b application.
1-10	On page 42 of 279 in HNP-F-PSA-0091, it is stated that no credit is taken for beneficial removal of water by floor drains. The SR requires that drainage capacity be accounted in the analyses.	IFSN-A4 says to, "ESTIMATE the capacity of the drains...[and] ACCOUNT for these factors in estimating flood volumes and SSC impacts from flooding." The capacity of the drains has been estimated, and their ability to impact flood volumes and flooding times has been assessed, thus satisfying this F&O. The locations of the floor drains, drain lines, and risers are shown in Attachment 4 of HNP-F/PSA-0091. All floor drains above the 190' elevation drain to the Floor Drain Transfer Tank (FDTT) which has a capacity of 1,000 gallons. When the tank fills to a high level set-point, it is automatically pumped to the Floor Drain Tank (FDT) in the Waste Processing Building	The IFPRA documentation was updated with analysis to validate the assumptions used to assess the impact of the floor drains. Resolution of this issue did

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
		(WPB). The FDT transfer pumps (2) each have a capacity of 35 gpm, and the FDT has a capacity of 25,000 gallons. A calculation of flow through a typical series of floor drains connected to a common drain line has been provided in revised Attachment 4 of HNP-F/PSA-0091. The calculation demonstrated that the common drain line/riser has excess capacity to remove water from multiple floor drains for spray scenarios with a flood source ≤100 gpm in any given flood compartment. The calculation also demonstrates that the common drain lines and floor drain system do not have sufficient capacity to remove water from multiple floor drains given a 2,000 gpm or larger flood source. For larger floods, the drain line capacities would be exceeded, the FDTT would fill quickly and overflow through its vent into the FDTT cubicle on the 190' elevation, and water would propagate from the flooded compartment to the lower levels through other propagation paths (as described in HNP-F/PSA-0092). For scenarios where 100 gpm ≤ flood source ≤ 2,000 gpm, the propagation analysis shows that removal of water through the floor drain system, and/or backflow through the drain lines, do not affect the volume of water that collects in a flood compartment or the timing of the scenario. Given these results, it is assumed that the floor drain system is credited for beneficial removal of water for spray scenarios where the break flow rate is ≤100 gpm. It is further assumed that the floor drain system does not have sufficient capacity to affect the timing for or mitigation of flood scenarios with break flows > 100 gpm; that backflow through drain lines has no impact on any scenario; and that propagation from the flood source through floor/wall penetrations and other flow paths in the flood compartment (as described in HNP-F/PSA-0092) will be the main impacts on the scenario. Section 6.3.1 of HNP-	not result in any changes to the PRA model. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
		F/PSA-0091 has been modified to clarify how floor drains were considered in the analysis.	
1-12	There was no consideration of failure of fluid sources located inside HVAC ducts. Cooling coils containing chilled water are located inside HVAC ducts. Depending on the plant configuration, failure of these components could result in propagation of water through the ducts to other areas. The potential for these scenarios exists and is required by the SR.	The HNP Internal Flooding analysis has been revised to consider the failure of cooling coils inside HVAC units and its consequences to other equipment. The analysis first looks at how cooling water leaves a HVAC unit and whether that has a potential to cause damage. If that potential couldn't be screened out, then a walk-down and evaluation of the scenario was conducted to verify the potential for the spread of damage. All air handlers were evaluated based on their ducting geometry from drawings and pictures. Those found to have an arrangement where the intake and exhaust ducts were on top of the unit was deemed to not be a credible flood source, given the low pressure and limited capacity of the Services Chilled Water Systems. Those found to have a more vulnerable arrangement (i.e. ducting on the sides or bottom of the unit) were walked down and their intake and exhaust ducting followed to determine if the flow path would negatively affect any SSCs. The write-up to support the analysis of the potential failure of fluid sources located within the HVAC ducts is documented in the areas and sources calculation, HNP-F/PSA-0091, revision 1. The results of the HVAC unit walk-downs are available in Attachment 88 of the walk-downs calculation, HNP-F/PSA-0090, revision 1.	Potential fluid sources in the HVAC ducts were assessed and incorporated into the scenario analysis for the IFPRA per the Standard. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
1-13	Screening of flood areas is documented in Attachment 8 and Attachment 9 of HNP-F-PSA-0092. The screening criteria for flood areas given in SR IFSN-A12 and IFSN-A13 require that the events do not cause reactor trip or immediate reactor shutdown. That potential was not assessed.	Flood compartments have be re-screened based on the criteria given in SR IFSN-A12 and IFSN-A13, and are the results of the screening are documented in Table 6-10 of the Areas and Sources calculation, HNP-F/PSA-0091. Attachments 8 and 9, and new Attachment 10, of HNP-F-PSA-0092, along with the text in the body of the calculation, have been significantly revised to correctly describe the scenario assessment that was performed for the flood compartments that were not screened.	Flood areas were re-screened per the Standard, and the IFPRA documentation has been updated accordingly. No further analysis is required for the 5b application.
1-14	Assumption 5 of HNP-F-PSA-0092 states "Smaller critical components such as valves and pressure, level, and flow transmitters that are sealed are not considered in the spray analysis. Photos of valves and transmitters taken during the walkdown indicate that the electrical portions of these components are covered and/or sealed (photos documented in Attachment 8). Therefore, these components are also excluded from the analysis." There is no engineering basis for excluding these components from the effects of spray. A basis to justify continued operability of components is required by SR IFSN-A7.	Used two methods to provide the engineering basis to support the assumption that all PRA-related AOVs and transmitters at HNP will operate as designed during and after being subjected to a liquid spray event. First used the Environmental Qualification program to list the components supported by this classification. Then used vendor manuals with NEMA classifications to determine what environments these components are designed to withstand and operate correctly. Attachment 8 was added to HNP-F/PSA-0091 and presents our findings from these two methods and concludes that all PRA-related AOVs and transmitters at HNP will operate as designed during and after a liquid spray event.	The IFPRA documentation was updated to validate the assumptions used to assess the impact of spray on the identified equipment. Resolution of this F&O did not result in any changes to the IFPRA model. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review

F&O #	Finding	Resolution	5b Impact
1-15	The basis for screening flood sources is provided in Table 6-6 of HNP-F-PSA-0091 and Attachments 8 and 9 of HNP-F-PSA-0092. The screening criteria used for flood sources do not match the criteria specified in SR IFSN-A15. The bases for screening flood sources given in SR IFSN-A15 were not used for the system in Table 6-6 of HNP-F-PSA-0091 and no justification for using alternative criteria was provided.	Flood sources were re-screened using criteria in SR IFSN-A15. Section 3-1, Table 6-6, and new Attachment 7 of calculation HNP-F/PSA-0091 have been updated/added to document the bases for screening flood sources. Attachments 8 and 9 of HNP-F/PSA-0092 have been significantly revised to correctly describe the scenario assessment that was performed for the flood sources and compartments that were not screened. No sources were screened based on reliance on operator actions to prevent challenges to normal plant operations (per SR IFSN-A16, Capability Category III).	Flood sources were re-screened per the Standard, and the IFPRA documentation has been updated accordingly. No further analysis is required for the 5b application..
1-16	Flooding events caused by human induced actions such as overfilling of tanks, flow diversion etc., are not addressed. Considerations of such events is required by the SR.	Plant level pipe break data on floods caused by human-induced maintenance errors and generic best estimates of associated plant level flood frequencies are already included in Revision 3 of the EPRI pipe failure rate report (EPRI TR 3002000079). This includes human errors such as overfilling of tanks and flow diversion that result in floods. Section 7 of EPRI TR 3002000079 provides tables and estimates of plant-level flood frequencies to support the estimation of flood initiating event frequencies caused by these maintenance errors. It is important to note that this does not include human errors resulting in pressure boundary failures since they are already included in direct failures involving failure of the pressure boundary caused by degradation mechanisms, loading conditions, and human error. Following guidance on the use of generic plant level maintenance-induced flood frequencies to support IFPRAs as described in Section 7 of the EPRI pipe failure rate report, Section 6.8.3 of HNP-F/PSA-0093 Revision 000 has already addressed computation of flood frequencies by HNP flood compartment and fluid system that are associated with flooding events caused by human-	HNP-specific OE was reviewed and included in the analysis, and the documentation was updated to better describe the EPRI methodology used to assess the human induced actions in the IFPRA. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review

F&O #	Finding	Resolution	5b Impact
		induced actions. Furthermore, to complement these generic frequencies, HNP Operating Experiences (OE) have been reviewed for maintenance-induced flood events and documented in Section 6.8.1 of HNP-F/PSA-0093 Revision 000.	
1-18	The assessment of door failure heights is evaluated in HNP-F-PSA-0092, *section 6. The analysis of doors is* based entirely on assumptions. However, these assumptions are not listed in section 5 of the document. The standard requires that assumptions be listed and characterized.	Door failure assumptions have been revisited based on a civil calculation, HNP-C/RAB-1008 Rev. 0. This calc demonstrates the pressure a standard door adjacent to the Main Control Room can withstand to be at least 1.5 psig away from the doorframe with a safety factor of 4. This pressure loading was applied to a flooding scenario and new door failure heights were calculated. This is available in Section 6.1 of HNP-F/PSA-0092. Previous assumptions regarding door failure heights have been deleted or reworded.	Assessment of HNP-specific *door failure* has been incorporated into the IFPRA model and the documentation updated. No further analysis is required for the 5b application.
1-19	SR HR-G4 requires that the analyses be based on realistic estimates of the time to receive cues. The analyses used an assumption of 5 minutes to receive cues and assumed that service low pressure alarms would be received. Experience shows that only for extremely large breaks would low pressure alarms be received and no analyses were seen that justified use of low pressure alarms for the HNP flood scenarios. No evaluation of the time to receive drain and sump alarms was provided. The basis for timing of the events analyzed was a scenario	The HRA calculation (HNP-F/PSA-0094) has been revised to include a table that states the specific alarms to indicate floods in each flood area (Table 7-2). The HRA calculation has also been revised to include a table (Table 7-2) that documents the analysis of the RAB sump level alarms and the expected time to alarm for spray events as well as flood events in the respective flood area. The sumps are identified in attachment 6 of the HNP Internal Flooding Areas and Sources Calculation (HNP-F/PSA-0091). A discussion about the flood drain alarms for spray events are documented in F&Os 1-10 and 2-3. The new information has been incorporated into the HRA calculator for validation of timing and scenario development per the suggested resolution.	Updated HRA analysis has been incorporated into the IFPRA model. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	evaluated in the FSAR and that timing may not be applicable to the scenarios evaluated in the HNP IF PRA.		
1-20	Assumption 5 of HNP-F-PSA-0093 states that piping downstream of standby pump is only exposed to system pressure approximately 20 hours per year and, thus, an adjustment factor of 0.0023 is applied to the annual pipe break frequency. EPRI TR3002000079 states: "All piping system failures identified in the service data involving failure of the pressure boundary have been included in this evaluation. These include failures from degradation mechanisms, loading conditions, and human error." The inclusion of 'degradation mechanisms' in addition to 'loading conditions' implies that downstream pipe breaks can occur when the system is not under pressure. The assumption that downstream piping can only fail when the system is operating is non-conservative and does not account for gravity drain of a tank that provides suction to the pump, thus potentially underestimating the frequency of downstream pipe breaks.	Although the adjustment factor for standby fluid system pipe lines was calculated in the initial release of HNP-F-PSA-0093 in consideration of exposure time, it was conservatively ignored in initial computation of passive pipe break rates presented in HNP-F-PSA-0093. It is important to note that this adjustment factor was initially prepared in anticipation of specific flood scenarios for a particular flood compartment with standby lines, resulting in initiating events that challenge plant safety systems and functions. However, at the time of initial release of HNP-F-PSA-0093, a key input document (HNP-F-PSA-0092) that identifies these initiating events was not released yet and therefore there were no flood scenarios available for use with initiating event frequency calculation as well as this adjustment factor. As a result, pipe passive break rates for various HNP fluid systems were only computed for the initial release of HNP-F-PSA-0093, not initiating event frequencies for specific flood scenarios involving the standby lines adjusted by the adjustment factor. A resolution to this F&O only requires deleting Assumption 5 in the next revision of HNP-F-PSA-0093 since its use results in non-conservative estimates of initiating event frequencies as pointed out by the F&O.	Initiating event frequencies for standby fluid system piping have been calculated per the EPRI methodology, and the IFPRA documentation has been updated accordingly. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
2-1	Existing fire compartment definitions were used as much as possible to define flood compartments and those fire compartments generally were based on individual rooms. Where the boundaries of a flood compartment do not, a new flood compartment was defined. However, a number of the existing fire compartments include several individual rooms (e.g., FC17) which are not assigned individual flood compartment designations. Table A.1-2 in HFNP-F/-PSA-00921 provides the correlation of fire compartments to flood compartments. Flood compartments are defined in Table 6-2 of FHNP-F-/PSA-00912. The standard states that flood areas should defined "by dividing the plant into physically separate areas where a flood area is viewed as generally independent of other areas in terms of the potential for internal flood effects and flood propagation" and "at the level of INDIVIDUAL ROOMS OR COMBINED ROOMS/HALLS FOR WHICH PLANT DESIGN FEATURES EXIST TO RESTRICT FLOODING. However in a number of instances the analysis combines several rooms where design features (e.g., concrete walls, doors, etc.) provide separation between the rooms making them generally independent. For example, in FLC-17b the area between column lines B and E	There are two parts to the resolution of, and response to this F&O: 1) clarification on the alignment of the flood compartment (FLC) naming convention with the fire compartment (FC) naming convention; and 2) definition of additional compartments in the Reactor Auxiliary Building (RAB), elevation (EL) 236 to correct instances where rooms were inappropriately combined. First, the FLCs for the HNP IFPRA were defined by barriers and plant physical features that could physically restrict flooding (per the Standard). Each of the FLCs is bounded by walls, doors, curbs, or other barriers that will restrict flooding and flood propagation. The additional decision to align the FLC naming convention with the fire compartment (FC) naming convention was made for Duke Energy convenience. This alignment enables the names of the flood compartments to describe plant areas that are in the same general location as their corresponding fire compartment names. For example, FC17 and FLC17b are defined in accordance with the respective sections of the Standard requirements, and are both located on the 236 elevation of the reactor auxiliary building. Their boundaries are different (per the Standard) but they are in the same general area of the plant. This simplifies discussions on the various elements of the PRA models with our staff. The wording in the text has been modified to clarify that FLCs were defined by barriers and the naming convention was aligned with the fire PRA. Second, seven (7) new FLCs have been defined and added to the analysis of the 236 elevation of the reactor auxiliary building. Two of the original compartments, 17b and 20d, were large areas that were further divided to align with walls and barriers in the room.	Additional flood compartments have been identified and incorporated into the IFPRA analysis, and the IFPRA documentation has been updated accordingly. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
	as well as column lines 41 and 43 make the areas independent although the compartment definition combines these areas.	General area drawing 5-G-0016 in Attachment 1 has been updated. In addition, the text of the document has been modified to include these new FLCs in all affected tables, section write-ups, and subsequent analyses.	
2-2	HNP-F-PSA-0091 states in a number of places that backflow through the drain system is screened from consideration as a flood source due to the existence of traps in the drain piping. There is no documented basis for the capacities of such traps and their ability to prevent backflow into rooms in which a flooding event does not originate. Consideration of drain backflow is required by the SR.	The statement regarding flow traps has been removed and replaced with an assessment of the potential effects of backflow on the propagation analysis. The propagation model documented in HNP-F/PSA-0092 was used to perform a sensitivity analysis to ascertain the importance of drain backflow. In order to simulate flow from one compartment to another through a drain line, a 4-inch diameter direct connection (i.e., a diameter larger than the 3-inch floor drain piping) was made between flooded and un-flooded compartments at the floor level. This direct connection was in addition to the inter-area propagation paths identified from plant walkdowns and modeled in the propagation analysis. Several cases were run in the sensitivity analysis, including assessment of combinations of flow from/to large and small compartments for the most limiting break in the plant. No appreciable difference in timing to SSC submergence or damage was noted for any case considered. As a result, backflow has been evaluated and determined to be of no incremental impact to the inter-area propagation analysis. Discussion of the backflow sensitivity analysis has been modified in appropriate places in both HNP-F/PSA-0091 and HNP-F/PSA-0092.	Sensitivity analyses were performed to validate the assumptions on potential effects of backflow through floor drains, and the IFPRA documentation has been corrected and updated accordingly. Resolution of this F&O did not result in any changes to the PRA model. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
2-3	While Attachments 1-4 of HNP-F-PSA-0094 identifies the automatic and manual actions that have the ability to terminate or contain propagation for the four events requiring HRA, the documentation does not include similar actions for the remaining sources and areas. Identification of the actions is required by the SR.	Section 7.2 of HNP-F/PSA-0094 has been modified to include the following information: All floor drains and equipment drains above the 190' elevation drain to the Floor Drain Transfer Tank (FDTT) or the Equipment Drain Tank (EDT) respectively. When these tanks reach a high level set-point they are *automatically* pumped to the Floor Drain Tank (FDT) and Waste Hold-up Tanks (WHT) respectively. There are also Hi-Hi FDTT and EDTT Level Alarms that would prompt operators to take manual actions if the automatic features failed (APP-105 1-1 and APP-105 1-3 respectively). Although this action will not keep up with the higher flow-rates expected from a flood or major flood this action will aid in containing the propagation of flood waters to the extent of the drain system and the capacity of the transfer pumps. Although these drains are not credited in the HNP internal flooding analysis it still demonstrates an "automatic action that would be used to contain propagation" as stated by the peer review team to help satisfy this comment. Once the FDTs and WHTs are 85% capacity operators will receive an alarm that should prompt them to *manually* align the pumps to additional tanks to aid in mitigating the propagation of flood waters. There are sumps in the RAB 190', Service Water Tunnel (216') and the RAB 236' elevations that will automatically pump down thus aiding in the mitigation of flood water accumulation. These sumps are identified in table 7-4 which also displays their respective volume, alarm and calculated time to alarm. Additional manual actions are documented in Table 7-2 of	The HRA analysis and IFPRA documentation have been updated to include the impacts of automatic and manual actions. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
		HNP-F/PSA-0094. This table has been modified to include a column that corresponds to each flood compartment that states the manual actions to isolate or mitigate flood propagation. Procedural guidance is provided to direct operators to manually mitigate the accumulation of flood waters in step 3.10.g of AOP-022 which states: "EVALUATE opening doors to adjacent non-critical areas to limit rise in water level at the break location." These automatic and manual flood mitigation actions have been discussed and confirmed with Operations and documented in the HRA Calculator.	
2-4	Not all flood failure mechanisms are considered in the susceptibility of components to flood-induced failures. HELBs alone can result in high humidity and temperature which in turn will result in fire sprinkler discharge. Assessment of these failure mechanisms is required by RG 1.200.	An analysis of high energy line breaks (HELBs) has been performed, and a new appendix describing the analysis has been added to the HNP-F/PSA-0091 calculation. The accident scenarios have been updated to include HELBs and the resulting effects. Jet impingement, pipe whip, high temperature and high humidity effects have been considered.	HELB analysis has been performed and incorporated in the IFPRA model and IFPRA documentation per the Standard. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
2-8	While a great number of maintenance-induced flooding frequencies were calculated, no evidence could be found that they were ever included in the model. The value for each of these events is significant when compared to the pipe break frequency values used in the same areas. Therefore, consideration of maintenance-induced events could have a significant effect on the overall results.	In communications with Operations personnel, it was determined that the only maintenance-induced flooding events that would occur in Mode 1 are located in the RAB 236' and 261' elevations (FLC17b and FLC18a, respectively). Specifically, they are the CCW heat exchangers and the ESCW chillers. These two flood compartments' decision trees were altered to include Maintenance-Induced as a failure mechanism and scenarios were developed for them. This can be found documented in Sections 7.3.4 and 7.4.2 of HNP-F/PSA-0092 as well as Attachment 9 of the same calc.	Maintenance-induced flooding has been incorporated into the IFPRA model for appropriate flood compartments. No further analysis is required for the 5b application.
2-11	The FRANX software was used to quantify the HNP internal flooding model which utilizes the fault tree linking approach. SR QU-A2 of Section 2.2-7 states that the frequencies of individual sequences need to be estimated for CDF and this was not done for internal flooding.	CDF results are now reported by event tree sequence in Revision 1 of HNP-F/PSA-0095.	Quantification results have been reported per the Standard, and the IFPRA documentation has been updated. No further analysis is required for the 5b application.

Table 1. Resolution of F&Os from HNP internal flooding PRA peer review			
F&O #	Finding	Resolution	5b Impact
2-12	The FRANX software was used to quantify the HNP internal flooding model which utilizes the fault tree linking approach. The FRANX model is configured to apply recovery actions. A truncation of 1E-08 was applied for the CCDP which is considered sufficiently low to capture an appropriate number of cutsets to calculate an accurate CDF. The flooding model was quantified similarly to the internal events model which included the removal of cutsets with mutually exclusive events. Section 4.7.2 of HFP-F-PSA-0095 states that the new HEPs associated with flooding were assumed to be independent of any other HEP in a scenario, however QU-C2 in Section 2.2-7 states that dependency between HEPs in a cutset or sequence must be assessed.	The HNP dependency analysis is now included in of Revision 1 of HNP-F/PSA-0094, HNP Internal Flooding HRA Calculation. This dependency analysis is located in Section 7.7 which states: The top combinations of operator actions identified in cutset reviews all had a CCDP of 1.0 therefore any operator actions beyond the securing of the flood were not dependent. The remaining operator action combination cutsets were analyzed and determined to be of such low value (i.e. E-8) that their impact on results were negligible. This is because the time between the necessary actions to be performed were long term (essentially hours) and thus the dependency was determined to be non-existent. The Internal events dependency values are addressed in the initial version of the IFPRA HRA calculation. Some initiating event operator actions were removed from combinations of actions. This is because OPER-D64 was inappropriately used in the combination determination for several other combinations, namely OPER-T58, OPER-T59, OPER-Q17, OPER-Q18, OPER-Q21, OPER-Q24 and OPER-Q25. The internal events operator actions have been reviewed and appropriately penalized based on the available cues and the timing of actions with relation to the internal flooding event and the associated actions. The applied penalties are detailed in section 7.1. The expected actions related to flooding events are captured in table 7-7. This table lists the typical internal events operator actions as they relate to the flooding scenarios and evaluates those actions during the flood event as well as the associated penalties.	HNP dependency analysis has been completed and included in the HRA and in updated IFPRA documentation. No further analysis is required for the 5b application.

HNP-15-040

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / RENEWED LICENSE NO. NPF-63

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

Enclosure 3

Proposed Technical Specification Changes
(124 pages including cover)

TABLE 1.1

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 184 days.
R	At least once per 18 months.
S/U	Prior to each reactor startup.
N.A.	Not applicable.
P	Completed prior to each release.
SFCP	At the frequency specified in the Surveillance Frequency Control Program

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - MODES 1 AND 2

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to 1770 pcm for 3-loop operation.

APPLICABILITY: MODES 1 and 2*.

ACTION:

With the SHUTDOWN MARGIN less than 1770 pcm, immediately initiate and continue boration at greater than or equal to 30 gpm of a solution containing greater than or equal to 7000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1770 pcm:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s);

at the frequency specified in the Surveillance Frequency Control Program

b. When in MODE 1 or MODE 2 with K_{eff} greater than or equal to 1 ~~at least once per 12 hours~~ by verifying that control bank withdrawal is within the limits of Specification 3.1.3.6;

Within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.6; and

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors below, with the control banks at the maximum insertion limit of Specification 3.1.3.6:

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*See Special Test Exceptions Specification 3.10.1.

SURVEILLANCE REQUIREMENTS (Continued)

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

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within ±1000 pcm ~~at least once per 31 Effective Full Power Days (EFPD)~~. This comparison shall consider at least those factors stated in Specification 4.1.1.1.1d., above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 EFPD after each fuel loading. If later experience shows adjustment is desirable at approximately 60 EFPD, the adjustment is permissible.

at the frequency specified in the Surveillance Frequency Control Program

SHUTDOWN MARGIN - MODES 3, 4, AND 5

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to the limit specified in the CORE OPERATING LIMITS REPORT (COLR), plant procedure PLP-106.

APPLICABILITY: MODES 3, 4, AND 5.

ACTION:

With the SHUTDOWN MARGIN less than the required value immediately initiate and continue boration at greater than or equal to 30 gpm of a solution containing greater than or equal to 7000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to the required value:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s); and

b. ~~At least once per 24 hours~~ At the frequency specified in the Surveillance Frequency Control Program by consideration of the following factors:

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

3/4.1.2 BORATION SYSTEMS

FLOW PATH - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from the boric acid tank via either a boric acid transfer pump or a gravity feed connection and a charging/safety injection pump to the Reactor Coolant System if the boric acid tank in Specification 3.1.2.5a. or 3.1.2.6a. is OPERABLE, or

b. The flow path from the refueling water storage tank via a charging/safety injection pump to the Reactor Coolant System if the refueling water storage tank in Specification 3.1.2.5b. or 3.1.2.6b. is OPERABLE.

APPLICABILITY: MODES 4*, 5*, and 6*.

ACTION:

With none of the above flow paths OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

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

a. At least once per 7 days by verifying that the temperature of the flow path between the boric acid tank and the charging/safety injection pump suction header is greater than or equal to 65°F when a flow path from the boric acid tank is used, and

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

at the frequencies specified in the Surveillance Frequency Control Program by

* A maximum of one charging/safety injection pump shall be OPERABLE whenever the temperature of one or more of the RCS cold legs is less than or equal to 325°F and the reactor vessel head is in place.

REACTIVITY CONTROL SYSTEMS

FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

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

a. The flow path from the boric acid tank via a boric acid transfer pump and a charging/safety injection pump to the Reactor Coolant System (RCS), and

b. Two flow paths from the refueling water storage tank via charging/ safety injection pumps to the RCS.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With only one of the above required boron injection flow paths to the RCS OPERABLE, restore at least two boron injection flow paths to the RCS to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN as specified in the CORE OPERATING LIMITS REPORT (COLR), plant procedure PLP-106 at 200°F within the next 6 hours; restore at least two flow paths to OPERABLE status within the next 7 days or be in HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.2 At least two of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the flow path between the boric acid tank and the charging/safety injection pump suction header tank is greater than or equal to 65°F when a flow path from the boric acid tank is used;

At the frequencies specified in the Surveillance Frequency Control Program by

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

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

d. ~~At least once per 18 months by~~ verifying that the flow path required by Specification 3.1.2.2a. delivers at least 30 gpm to the RCS.

BORATED WATER SOURCE - SHUTDOWN

LIMITING CONDITION FOR OPERATION

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

a. The boric acid tank with:

1. A minimum contained borated water volume of 7150 gallons which is ensured by maintaining indicated level of greater than or equal to 23%,

2. A boron concentration of between 7000 and 7750 ppm, and

3. A minimum solution temperature of 65°F.

b. The refueling water storage tank (RWST) with:

1. A minimum contained borated water volume of 106,000 gallons, which is equivalent to 12% indicated level,

2. A boron concentration of between 2400 and 2600 ppm, and

3. A minimum solution temperature of 40°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

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

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

1. Verifying the boron concentration of the water,

2. Verifying the contained borated water volume, and

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

b. ~~At least once per 24 hours~~ by verifying the RWST temperature when it is the source of borated water and the outside air temperature is less than 40°F.

At the frequency specified in the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

4.1.2.6 Each borated water source shall be demonstrated OPERABLE:

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

1. Verifying the boron concentration in the water,

2. Verifying the contained borated water volume of the water source, and

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

At the frequency specified in the Surveillance Frequency Control Program

b. ~~At least once per 24 hours~~ by verifying the RWST temperature when the outside air temperature is either less than 40°F or greater than 125°F.

LIMITING CONDITION FOR OPERATION

ACTION (Continued):

remain valid for the duration of operation under these conditions;

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

c) A power distribution map is obtained from the movable incore detectors and $F_Q(Z)$ and $F^N_{\Delta H}$ are verified to be within their limits within 72 hours; and

d) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within the next hour and within the following 4 hours the High Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each rod shall be determined to be within the group demand limit by verifying the individual rod positions ~~at least once per 12 hours~~ except during time intervals when the rod position deviation monitor is inoperable, then verify the group positions at least once per 4 hours.

4.1.3.1.2 Each rod not fully inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction ~~at least once per 92 days~~.

at the frequency specified in the Surveillance Frequency Control Program

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEMS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2 The Digital Rod Position Indication System and the Demand Position Indication System shall be OPERABLE and capable of determining the shutdown and control rod positions within ± 12 steps.

APPLICABILITY: MODES 1 and 2.

ACTION:

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

1. Determine the position of the nonindicating rod(s) indirectly by the movable incore detectors at least once per 8 hours and immediately after any motion of the nonindicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, or

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

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

1. Verify that all digital rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 12 steps of each other at least once per 8 hours, or

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

SURVEILLANCE REQUIREMENTS

4.1.3.2 Each digital rod position indicator shall be determined to be OPERABLE by verifying that the Demand Position Indication System and the Digital Rod Position Indication System agree within 12 steps ~~at least once per 12 hours~~ except during time intervals when the rod position deviation monitor is inoperable, then compare the Demand Position Indication System and the Digital Rod Position Indication System at least once per 4 hours.

at the frequency specified in the Surveillance Frequency Control Program

POSITION INDICATION SYSTEM - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 One digital rod position indicator (excluding demand position indication) shall be OPERABLE and capable of determining the rod position within ± 12 steps for each shutdown or control rod not fully inserted.

APPLICABILITY: MODES 3* **, 4* **, and 5* **.

ACTION:

ACTION:

a. With one of the above required position indicator(s) inoperable, either restore the indicator to OPERABLE within 8 hours or open the Reactor Trip System breakers.

b. With more than one of the above required position indicators inoperable, immediately open the Reactor Trip System breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required digital rod position indicator(s) shall be determined to be OPERABLE by verifying that the digital rod position indicators agree with the demand position indicators within 12 steps when exercised over the full-range of rod travel ~~at least once per 18 months~~.

at the frequency specified in the Surveillance Frequency Control Program

*With the Reactor Trip System breakers in the closed position.

**See Special Test Exceptions Specification 3.10.5.

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual shutdown and control rod drop time from the fully withdrawn position shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 551°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

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

b. With the rod drop times within limits but determined with two reactor coolant pumps operating, operation may proceed provided THERMAL POWER is restricted to less than or equal to 66% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of shutdown and control rods shall be demonstrated through measurement prior to reactor criticality:

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

b. For specifically affected individual rods following any maintenance on or modification to the Control Rod Drive System which could affect the drop time of those specific rods, and

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

At the frequency specified in the Surveillance Frequency Control Program.

SHUTDOWN ROD INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown rods shall be fully withdrawn as specified in the CORE OPERATING LIMITS REPORT (COLR), plant procedure PLP-106.

APPLICABILITY: MODES 1* and 2* **.

ACTION:

With a maximum of one shutdown rod not fully withdrawn as specified in the COLR, except for surveillance testing pursuant to Specification 4.1.3.1.2, within 1 hour either:

a. Fully withdraw the rod, or

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

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown rod shall be determined to be fully withdrawn as specified in the COLR:

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

b. ~~At least once per 12 hours~~ thereafter.

At the frequency specified in the Surveillance Frequency Control Program

*See Special Test Exceptions Specifications 3.10.2 and 3.10.3.
**With K_{eff} greater than or equal to 1.

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control banks shall be limited in physical insertion as specified in the CORE OPERATING LIMITS REPORT (COLR), plant procedure PLP-106.

APPLICABILITY: MODES 1* and 2* **.

ACTION:

With the control banks inserted beyond the insertion limit specified in the COLR, except for surveillance testing pursuant to Specification 4.1.3.1.2:

a. Restore the control banks to within the insertion limit specified in the COLR within 2 hours, or

b. Reduce THERMAL POWER within 2 hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the insertion limits specified in the COLR, or

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

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each control bank shall be determined to be within the insertion limit specified in the COLR ~~at least once per 12 hours~~ at the frequency specified in the Surveillance Frequency Control Program except during time intervals when the rod insertion limit monitor is inoperable, then verify the individual rod positions at least once per 4 hours.

*See Special Test Exceptions Specifications 3.10.2 and 3.10.3.

**With K_{eff} greater than or equal to 1.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AFD shall be determined to be within its limits during POWER OPERATION above 50% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel ~~at least once per 7 days~~ when the AFD Monitor Alarm is OPERABLE, and

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

4.2.1.2 The indicated AFD shall be considered outside of its limits when two or more OPERABLE excore channels are indicating the AFD to be outside the limits.

4.2.1.3 The target AFD of each OPERABLE excore channel shall be determined by excore measurement ~~at least once per 31 Effective Full Power Days~~ in conjunction with the requirements of Specification 4.2.2.2. The target AFD may be updated between measurements by adding the most recently measured value and the change in the predicted value since the measurement. The provisions of Specification 4.0.4 are not applicable.

at the frequency specified in the Surveillance Frequency Control Program

4.2.2.1 The provisions of Specification 4.0.4 are not applicable.

4.2.2.2 $F_Q(Z)$ shall be evaluated to determine if it is within its limit by:

a. Using the movable incore detectors to obtain a power distribution map at any THERMAL POWER greater than 5% of RATED THERMAL POWER.

b. Increasing the measured $F_Q(Z)$ component of the power distribution map by 3% to account for manufacturing tolerances and further increasing the value by 5% to account for measurement uncertainties. Verify the requirements of Specification 3.2.2 are satisfied.

c. Satisfying the following relationship:

$$F_Q^M(Z) \leq \frac{F_Q^{RTP} \times K(Z)}{P \times V(Z)} \text{ for } P > 0.5$$

$$F_Q^M(Z) \leq \frac{F_Q^{RTP} \times K(Z)}{V(Z) \times 0.5} \text{ for } P \leq 0.5$$

where $F_Q^M(Z)$ is the measured $F_Q(Z)$ increased by the allowances for manufacturing tolerances and measurement uncertainty, F_Q^{RTP} is the F_Q limit, $K(Z)$ is the normalized $F_Q(Z)$ as a function of core height, P is the fraction of RATED THERMAL POWER, and $V(Z)$ is the function that accounts for power distribution transients encountered during normal operation. F_Q^{RTP}, $K(Z)$, and $V(Z)$ are specified in the COLR.

d. Measuring $F_Q^M(Z)$ according to the following schedule:

1. Upon achieving equilibrium conditions after exceeding by 10% or more of RATED THERMAL POWER, the THERMAL POWER at which $F_Q(Z)$ was last determined,* or

2. ~~At least once per 31 Effective Full Power Days~~, whichever occurs first.

At the frequency specified in the Surveillance Frequency Control Program

* During power escalation at the beginning of each cycle, power level may be increased until a power level for extended operation has been achieved and a power distribution map obtained.

3/4.2.3 NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 $F_{\Delta H}$ shall be determined to be within acceptable limits:

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

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

At the frequency specified in the Surveillance Frequency Control Program

LIMITING CONDITION FOR OPERATION

ACTION (Continued):

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

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

1

SURVEILLANCE REQUIREMENTS

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

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

at the frequency specified in the Surveillance Frequency Control Program

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

4.2.4.2 The QUADRANT POWER TILT RATIO shall be determined to be within the limit when above 75% of RATED THERMAL POWER with one Power Range channel inoperable by using the movable incore detectors to confirm that the normalized symmetric power distribution, obtained from two sets of four symmetric thimble locations or full-core flux map, is consistent with the indicated QUADRANT POWER TILT RATIO ~~at least once per 12 hours~~.

at the frequency specified in the Surveillance Frequency Control Program

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System $T_{avg} \leq 594.8°F$ after addition for instrument uncertainty, and

b. Pressurizer Pressure $\geq$ 2185 psig* after subtraction for instrument uncertainty, and

c. RCS total flow rate $\geq$ 293,540 gpm after subtraction for instrument uncertainty.

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters not within its specified limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters shown in Specification 3.2.5 shall be verified to be within its limit ~~at least once per 12 hours~~.

4.2.5.2 Verify, by precision heat balance, that RCS total flow rate is within its limit ~~at least once per 18 months~~.**

at the frequency specified in the Surveillance Frequency Control Program

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* This limit is not applicable during either a THERMAL POWER Ramp in excess of ±5% RATED THERMAL POWER per minute or a THERMAL POWER step change in excess of ±10% RATED THERMAL POWER.

** Required to be performed within 24 hours after $\geq$ 95% RATED THERMAL POWER.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the Reactor Trip System instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION: As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each Reactor Trip System instrumentation channels and interlock and the automatic trip logic shall be demonstrated OPERABLE by the performance of the Reactor Trip System Instrumentation Surveillance Requirements specified in Table 4.3-1.

4.3.1.2 The REACTOR TRIP SYSTEM RESPONSE TIME of each Reactor trip function shall be verified to be within its limit, specified in the Technical Specification Equipment List Program, plant procedure PLP-106, ~~at least once per 18 months~~. ~~Each verification shall include at least one train such that both trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once every N times 18 months where N is the total number of redundant channels in a specific Reactor trip function as shown in the "Total No. of Channels" column of Table 3.3-1~~.

at the frequency specified in the Surveillance Frequency Control Program

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	~~R~~(12)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	~~S~~	~~D~~(2, 4), ~~#~~(3, 4), ~~##~~(4, 6), ~~R~~(4, 5)	~~Q~~	N.A.	N.A.	1, 2
b. Low Setpoint	~~S~~	~~R~~(4)	S/U(1)	N.A.	N.A.	1***, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	~~R~~(4)	~~Q~~	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	~~R~~(4)	~~Q~~	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	~~S~~	~~R~~(4, 5)	S/U(1)	N.A.	N.A.	1***, 2
6. Source Range, Neutron Flux	~~S~~	~~R~~(4, 5)	S/U(1), ~~Q~~(8)	N.A.	N.A.	2**, 3, 4, 5
7. Overtemperature ΔT	~~S~~	R(11)	~~Q~~	N.A.	N.A.	1, 2
8. Overpower ΔT	~~S~~	~~R~~	~~Q~~	N.A.	N.A.	1, 2
9. Pressurizer Pressure--Low	~~S~~	~~R~~	~~Q~~	N.A.	N.A.	1 (16)
10. Pressurizer Pressure--High	~~S~~	~~R~~	~~Q~~	N.A.	N.A.	1, 2

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
11. Pressurizer Water Level-- High	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	1
12. Reactor Coolant Flow--Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	1
13. Steam Generator Water Level--Low-Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~(16) SFCP	N.A.	N.A.	1, 2 (16)
14. Steam Generator Water Level--Low Coincident with Steam/Feedwater Flow Mismatch	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	1, 2
15. Undervoltage--Reactor Coolant Pumps	N.A.	~~R~~ SFCP	N.A.	~~Q~~(9) SFCP	N.A.	1
16. Underfrequency--Reactor Coolant Pumps	N.A.	~~R~~ SFCP	N.A.	~~Q~~(9) SFCP	N.A.	1
17. Turbine Trip						
a. Low Fluid Oil Pressure	N.A.	~~R~~ SFCP	N.A.	S/U(1, 9)	N.A.	1
b. Turbine Throttle Valve Closure	N.A.	~~R~~ SFCP	N.A.	S/U(1, 9)	N.A.	1
18. Safety Injection Input from ESF	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	1, 2
19. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	~~R~~(4) SFCP	~~R~~ SFCP	N.A.	N.A.	2**

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
19 Reactor Trip System Interlocks (Continued)						
b. Low Power Reactor Trips Block, P-7	N.A.	~~R~~(4)	~~R~~	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	~~R~~(4) SFCP	~~R~~	N.A.	N.A.	1
d. Power Range Neutron Flux P-10	N.A.	~~R~~(4)	~~R~~	N.A.	N.A.	1, 2
e. Turbine Inlet Pressure, P-13	N.A.	~~R~~	~~R~~	N.A.	N.A.	1
20 Reactor Trip Breaker	N.A.	N.A.	N.A.	~~M~~ (7, 9, 10)	N.A.	1, 2, 3*, 4*, 5*
21 Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A. SFCP	~~M~~ (7)	1, 2, 3*, 4*, 5*
22 Reactor Trip Bypass Breaker	N.A.	N.A.	N.A.	~~M~~ (7, 13) ~~R~~(14) SFCP	N.A.	1, 2, 3*, 4*, 5*

TABLE 4.3-1 (Continued)

TABLE NOTATIONS

*When the Reactor Trip System breakers are closed and the Control Rod Drive System is capable of rod withdrawal.

**Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

***Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

~~#Each 31 Effective Full Power Days.~~ DELETED

~~##Each 92 Effective Full Power Days.~~

(1) If not performed in previous 31 days.

(2) Comparison of calorimetric to excore power indication above 15% of RATED THERMAL POWER. Adjust excore channel gains consistent with calorimetric power if absolute difference is greater than 2%. The provisions of Specification 4.0.4 are not applicable to entry into MODE 2 or 1.

(3) Single point comparison of incore to excore AXIAL FLUX DIFFERENCE above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

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

(5) Detector plateau curves shall be obtained, and evaluated and compared to manufacturer's data. For the Intermediate Range and Power Range Neutron Flux channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) Incore - Excore Calibration, above 75% of RATED THERMAL POWER. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) Each train shall be tested At the frequency specified in the Surveillance Frequency Control Program ~~at least every 62 days on a STAGGERED TEST BASIS.~~

(8) ~~Quarterly surveillance~~ Surveillance in MODES 3*, 4*, and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window.

(9) Setpoint verification is not applicable.

(10) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall independently verify the OPERABILITY of the undervoltage and shunt trip attachments of the reactor trip breakers.

NO CHANGES THIS PAGE

TABLE NOTATIONS (Continued)

(11) CHANNEL CALIBRATION shall include the RTD response time.

(12) Verify that appropriate signals reach the undervoltage and shunt trip relays, for both the main and bypass breakers, from the manual reactor trip switch.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each ESFAS instrumentation channel and interlock and the automatic actuation logic and relays shall be demonstrated OPERABLE by performance of the ESFAS Instrumentation Surveillance Requirements specified in Table 4.3-2.

4.3.2.2 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be verified to be within its limit specified in the Technical Specification Equipment List Program, plant procedure PLP-106, ~~at least once per 18 months~~. ~~Each verification shall include at least one train such that both trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" column of Table 3.3-3~~.

at the frequency specified in the Surveillance Frequency Control Program

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection (Reactor Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Containment Ventilation Isolation, Phase A Containment Isolation, Start Auxiliary Feedwater System Motor-Driven Pumps, Start Containment Fan Coolers, Start Emergency Service Water Pumps, Start Emergency Service Water Booster Pumps)								
a. Manual Initiation	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	SFCP ~~M~~(1)	~~M~~(1) SFCP	~~Q~~(3) SFCP	1, 2, 3, 4
c. Containment Pressure--High-1	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
d. Pressurizer Pressure--Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Steam Line Pressure--Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
2. Containment Spray								
a. Manual Initiation	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~ SFCP	1, 2, 3, 4
c. Containment Pressure--High-3	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2, 3
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual Initiation	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~(3) SFCP	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								
1) Manual Containment Spray Initiation	See Item 2.a. above for Manual Containment Spray Surveillance Requirements.							
2) Automatic Actuation Logic Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~ SFCP	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation (Continued)								
3) Containment Pressure--High-3	~~S~~	~~R~~	~~Q~~	N.A.	N.A.	N.A.	N.A.	1, 2, 3
	SFCP							
c. Containment Ventilation Isolation								
1) Manual Containment Spray Initiation	See Item 2.a. above for Manual Containment Spray Surveillance Requirements.							
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1, 2)	~~M~~(1, 2)	~~Q~~(2)	1, 2, 3, 4, 6#
						SFCP		
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Radioactivity								
a) Area Monitors (both preentry and normal purges)	See Table 4.3-3, Item 1a, for surveillance requirements.							
b) Airborne Gaseous Radioactivity								
(1) RCS Leak Detection (normal purge)	See Table 4.3-3, Item 1b1, for surveillance requirements.							

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation (Continued)								
(2) Preentry Purge Detector	See Table 4.3-3, Item 1b2, for surveillance requirements.							
c) Airborne Particulate Radioactivity								
(1) RCS Leak Detection (normal purge)	See Table 4.3-3, Item 1C1, for surveillance requirements.							
(2) Preentry Purge Detector	See Table 4.3-3, Item 1C2, for surveillance requirements.							
5) Manual Phase A Isolation	See Item 3.a.1) above for Manual Phase A Isolation Surveillance Requirements.							
4. Main Steam Line Isolation								
a. Manual Initiation	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A	N.A	N.A.	~~M~~(1)(4) SFCP	~~M~~(1) SFCP	~~Q~~ SFCP	1, 2, 3, 4
c. Containment Pressure--High-2	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Main Steam Line Isolation (Continued)								
d. Steam Line Pressure--Low	See Item 1.e. above for Steam Line Pressure--Low Surveillance Requirements.							
e. Negative Steam Line Pressure Rate--High	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	3**, 4**
5. Turbine Trip and Feedwater Isolation								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~ SFCP	1, 2
b. Steam Generator Water Level--High-High (P-14)	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	N.A.	1, 2
c. Safety Injection	See Item 1. above for Safety Injection Surveillance Requirements.							
6. Auxiliary Feedwater								
a. Manual Initiation	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation and Actuation Relays	N.A.	N.A	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~ SFCP	1, 2, 3
c. Steam Generator Water Level--Low-Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A	N.A	1, 2, 3
d. Safety Injection Start Motor-Driven Pumps	See Item 1. above for all Safety Injection Surveillance Requirements.							
e. Loss-of-Offsite Power Start Motor-Driven Pumps and Turbine-Driven Pump	See Item 9. below for all Loss-of-Offsite Power Surveillance Requirements.							

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
6. Auxiliary Feedwater (Continued)								
f. Trip of All Main Feedwater Pumps Start Motor-Driven Pumps	N.A.	N.A.	N.A.	~~R~~ SFCP	N.A.	N.A.	N.A	1, 2
g. Steam Line Differential Pressure--High	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	~~Q~~(3) SFCP	1, 2, 3
Coincident With Main Steam Line Isolation (Causes AFW Isolation)	See Item 4. above for all Main Steam Line Isolation Surveillance Requirements.							
7. Safety Injection Switchover to Containment Sump								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~(3) SFCP	1, 2, 3, 4
b. RWST Level--Low-Low	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	N.A.	N.A.	N.A.	~~Q~~(3) SFCP	1, 2, 3, 4
Coincident With Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
8. Containment Spray Switchover to Containment Sump								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	~~Q~~(3) SFCP	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
8. Containment Spray Switchover to Containment Sump (Continued)								
b. RWST Level--Low-Low	See Item 7.b. above for RWST Level--Low-Low Surveillance Requirements.							
Coincident with Containment Spray	See Item 2. above for Containment Spray Surveillance Requirements.							
9. Loss-of-Offsite Power								
a. 6.9 kV Emergency Bus Undervoltage--Primary	N.A.	~~R~~ SFCP	N.A.	~~M*~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3, 4
b. 6.9 kV Emergency Bus Undervoltage--Secondary	N.A.	~~R.~~ SFCP	N.A.	~~M*~~ SFCP	N.A.	N.A.	N.A.	1, 2, 3, 4
10. Engineered Safety Features Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	~~R~~ SFCP	~~Q~~ SFCP	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	N.A.	1, 2, 3
Not P-11	N.A.	~~R~~ SFCP	~~Q~~ SFCP	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	N.A.	1, 2, 3
b. Low-Low T_{avg}, P-12	N.A.	~~R~~ SFCP	~~Q~~ SFCP	N.A.	~~M~~(1) SFCP	~~M~~(1) SFCP	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
10. Engineered Safety Features Actuation System Interlocks (Continued)								
c. Reactor Trip, P-4	N.A.	N.A.	N.A.	SFCP ~~R~~	N.A.	N.A.	N.A.	1,2,3
d. Steam Generator Water Level, P-14	See Item 5.b. above for P-14 Surveillance Requirements.							

At the frequency specified in the Surveillance Frequency Control Program

at the frequency specified in the Surveillance Frequency Control Program

TABLE 4.3-2 (Continued)

TABLE NOTATION

(1) Each train shall be tested ~~at least every 62 days on a STAGGERED TEST BASIS~~.

(2) The Surveillance Requirements of Specification 4.9.9 apply during CORE ALTERATIONS or movement of irradiated fuel in containment.

(3) Except for relays K601, K602, K603, K608, K610, K615, K616, K617, K622, K636, K739, K740 and K741 which shall be tested ~~at least once per 18 months~~ and during each COLD SHUTDOWN exceeding 72 hours unless they have been tested within the previous 92 days.

(4) The Steam Line Isolation-Safety Injection (Block-Reset) switches enable the Negative Steam Line Pressure Rate--High signal (item 4.e) when used below the P-11 setpoint. Verify proper operation of these switches each time they are used.

* Setpoint verification not required.

\# During CORE ALTERATIONS or movement of irradiated fuel in containment.

** Trip Function automatically blocked above P-11 and may be blocked below P-11 when safety injection or low steamline pressure is not blocked.

3/4.3.3 MONITORING INSTRUMENTATION

No changes on this page.

RADIATION MONITORING FOR PLANT OPERATIONS

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels for plant operations shown in Table 3.3-6 shall be OPERABLE with their Alarm/Trip Setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel Alarm/Trip Setpoint for plant operations exceeding the value shown in Table 3.3-6, adjust the Setpoint to within the limit within 4 hours or declare the channel inoperable.

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

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel for plant operations shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and DIGITAL CHANNEL OPERATIONAL TEST for the MODES and at the frequencies shown in Table 4.3-3.

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	DIGITAL CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Containment Radioactivity--				
a. Containment Ventilation Isolation Signal Area Monitors	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	1, 2, 3, 4, 6
b. Airborne Gaseous Radioactivity				
1) RCS Leakage Detection	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	1, 2, 3, 4
2) Pre-entry Purge	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP##	#
c. Airborne Particulate Radioactivity				
1) RCS Leakage Detection	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	1, 2, 3, 4
2) Pre-entry Purge	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP##	#
2. Spent Fuel Pool Area-- Fuel Handling Building Emergency Exhaust Actuation				
a. Fuel Handling Building Operating Floor--South Network	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	**
b. Fuel Handling Building Operating Floor--North Network	~~S~~ SFCP	~~R~~ SFCP	~~Q~~ SFCP	*

TABLE 4.3-3 (Continued)

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	DIGITAL CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Control Room Outside Air Intakes				
a. Normal Outside Air Intake Isolation	~~S~~	~~R~~	~~Q~~	1,2,3,4,5,6 and during movement of irradiated fuel assemblies and movement of loads over spent fuel pools.
b. Emergency Outside Air Intake Isolation--South Intake	~~S~~	~~R~~	~~Q~~	1,2,3,4,5,6 and during movement of irradiated fuel assemblies and movement of loads over spent fuel pools.
c. Emergency Outside Air Intake Isolation--North Intake	~~S~~	~~R~~	~~Q~~	1,2,3,4,5,6 and during movement of irradiated fuel assemblies and movement of loads over spent fuel pools.

SFCP

TABLE NOTATIONS

* With irradiated fuel in the Northend Spent Fuel Pool or transfer of irradiated fuel from or to a spent fuel shipping cask.

** With irradiated fuel in the Southend Spent Fuel Pool or New Fuel Pool.

\# Whenever pre-entry purge system is to be used.

\#\# Prior to operation of pre-entry purge unless performed within the last 92 days.

REMOTE SHUTDOWN SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.3.5.a The Remote Shutdown System monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE.

3.3.3.5.b All transfer switches, Auxiliary Control Panel Controls and Auxiliary Transfer Panel Controls for the OPERABILITY of those components required by the SHNPP Safe Shutdown Analysis to (1) remove decay heat via auxiliary feedwater flow and steam generator power-operated relief valve flow from steam generators A and B, (2) control RCS inventory through the normal charging flow path, (3) control RCS pressure, (4) control reactivity, and (5) remove decay heat via the RHR system shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring channels less than the Minimum Channels OPERABLE as required by Table 3.3-9, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE remote shutdown monitoring channels less than the Total Number of Channels required by Table 3.3-9, restore the inoperable channels to OPERABLE status within 60 days or submit a Special Report in accordance with Specification 6.9.2 within 14 additional days.

c. With one or more inoperable Remote Shutdown System transfer switches, power, or control circuits required by 3.3.3.5.b, restore the inoperable switch(s)/circuit(s) to OPERABLE status within 7 days, or be in HOT STANDBY within the next 12 hours.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

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

4.3.3.5.2 Each Remote Shutdown System transfer switch, power and control circuit and control switch required by 3.3.3.5.b, shall be demonstrated OPERABLE ~~at least once per 18 months~~.

at the frequency specified in the Surveillance Frequency Control Program

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Coolant System Hot-Leg Temperature	~~M~~	~~R~~
2. Reactor Coolant System Cold-Leg Temperature	~~M~~	~~R~~
3. Pressurizer Pressure	~~M~~	~~R~~
4. Pressurizer Level	~~M~~	~~R~~
5. Steam Generator Pressure	~~M~~	~~R~~
6. Steam Generator Water Level--Wide Range	~~M~~	~~R~~
7. Residual Heat Removal Flow	~~M~~	~~R~~
8. Auxiliary Feedwater Flow	~~M~~	~~R~~
9. Condensate Storage Tank Level	~~M~~	~~R~~
10. Reactor Coolant System Pressure--Wide Range	~~M~~	~~R~~
11. Wide-Range Flux Monitor (SR Indicator)	~~M~~	~~Q~~
12. Charging Header Flow	~~M~~	~~R~~
13. a. Auxiliary Feedwater Turbine Steam Inlet--Pump Discharge ΔP	~~M~~	~~R~~
b. Auxiliary Feedwater Turbine Speed	~~M~~	~~R~~
14. Boric Acid Tank Level	~~M~~	~~R~~

Replace all with: SFCP

No changes this page.

LIMITING CONDITION FOR OPERATION

least HOT STANDBY in the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

f. The provisions of Specification 3.0.4 are not applicable.

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* The alternate method shall be a check of safety valve piping temperatures and evaluation to determine position.

\# The alternate method shall be the initiation of the backup method as required by Specification 6.8.4.d.

SURVEILLANCE REQUIREMENTS

4.3.3.6 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION at the frequencies shown in Table 4.3-7.

TABLE 4.3-7

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Containment Pressure		
a. Narrow Range	~~M~~	~~R~~
b. Wide Range	~~M~~	~~R~~
2. Reactor Coolant Hot-Leg Temperature--Wide Range	~~M~~	~~R~~
3. Reactor Coolant Cold-Leg Temperature--Wide Range	~~M~~	~~R~~
4. Reactor Coolant Pressure--Wide Range	~~M~~	~~R~~
5. Pressurizer Water Level	~~M~~	~~R~~
6. Steam Line Pressure	~~M~~	~~R~~
7. Steam Generator Water Level--Narrow Range	~~M~~	~~R~~
8. Steam Generator Water Level--Wide Range	~~M~~	~~R~~
9. Refueling Water Storage Tank Water Level	~~M~~	~~R~~
10. Auxiliary Feedwater Flow Rate	~~M~~	~~R~~
11. Reactor Coolant System Subcooling Margin Monitor	~~M~~	~~R~~
12. PORV Position Indicator	~~M~~	~~R~~
13. PORV Block Valve Position Indicator	~~M~~	~~R~~
14. Pressurizer Safety Valve Position Indicator	~~M~~	~~R~~
15. Containment Water Level (ECCS Sump)--Narrow Range	~~M~~	~~R~~
16. Containment Water Level--Wide Range	~~M~~	~~R~~

Replace all with: SFCP

1

TABLE 4.3-7 (Continued)

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Replace all with: SFCP

INSTRUMENT		CHANNEL CHECK	CHANNEL CALIBRATION
17.	In Core Thermocouples	~~M~~	~~R~~
18.	Plant Vent Stack--High Range Noble Gas Monitor	~~M~~	~~R~~
19.	Main Steam Line Radiation Monitors	~~M~~	~~R~~
20.	Containment--High Range Radiation Monitor	~~M~~	~~R~~*
21.	Reactor Vessel Level	~~M~~	~~R~~
22.	Containment Spray NaOH Tank Level	~~M~~	~~R~~
23.	Turbine Building Vent Stack High Range Noble Gas Monitor	~~M~~	~~R~~
24.	Waste Processing Building Vent Stack High Range Noble Gas Monitors		
	a. Vent Stack 5	~~M~~	~~R~~
	b. Vent Stack 5A	~~M~~	~~R~~
25.	Condensate Storage Tank Level	~~M~~	~~R~~

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