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10 CFR 50.90

June 11, 2004

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

Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

SUBJECT: License Amendment Request
Proposed Technical Specifications Change to Relocate Surveillance Test Intervals to a Licensee-Controlled Program (Risk-Informed Initiative 5b)

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (Exelon), hereby requests a change to the Technical Specifications (TS), Appendix A, of Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively.

The proposed change will relocate the surveillance test intervals (STIs) of various TS surveillance requirements from the TS to a licensee program controlled in accordance with the requirements of 10 CFR 50.59. Revisions to the STIs will be made in accordance with a new program, the Surveillance Frequency Control Program, which is being added to the Administrative Controls section of TS. Attachment 1 provides the evaluation of the proposed change. Attachments 2 and 3 provide a copy of the marked up TS pages for the proposed change for LGS, Units 1 and 2, respectively.

This license amendment request (LAR) is being submitted as a pilot submittal in support of the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b, "Relocate Surveillance Test Intervals to Licensee Control." This LAR is predicated on NRC approval of a risk-informed process and methodology developed by the BWROG Risk Informed Technical Specifications (RITS) Committee in concert with the Nuclear Energy Institute (NEI) for control of changes to STIs associated with TS surveillance requirements. The details of this risk-informed process and methodology are being submitted separately to the NRC for review and approval as part of Technical Specification Task Force (TSTF) 425. Exelon requests approval of this LAR in conjunction with NRC approval of TSTF-425.

Individual STIs will not be revised as part of this LAR; however, a summary of the results of several example STI evaluations using the proposed risk-informed methodology has been provided within Attachment 4 of this LAR. Once this LAR and the risk-informed process and methodology are approved by the NRC, future changes to the STIs will be evaluated in accordance with the licensee-controlled program, and the STIs may be revised, as appropriate, based on the evaluation results without prior NRC approval.

In addition, in support of the proposed change, Attachment 5 provides an evaluation of the technical adequacy of the LGS Probabilistic Risk Assessment (PRA) for this application relative to the guidance provided in NRC Regulatory Guide 1.200, For Trial Use (Draft was issued as DG-

A001

1122), "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-informed Activities," February 2004.

Exelon has concluded that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c).

Exelon requests approval of the proposed amendments by June, 2005. Once approved, the amendments shall be implemented within 60 days of issuance.

There are no regulatory commitments contained within this letter.

The proposed change has been reviewed by the Plant Operations Review Committee and approved by the Nuclear Safety Review Board.

Exelon is notifying the State of Pennsylvania of this application for changes to the TS and Operating License by transmitting a copy of this letter and its attachments to the designated State Official.

If you have any questions or require additional information, please contact Glenn Stewart at 610-765-5529.

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

Respectfully,

Executed on 06-11-04

Michael P. Gallagher
Director, Licensing & Regulatory Affairs
Exelon Generation Company, LLC

Attachments:
1. Evaluation of the Proposed Change
2. Technical Specifications Markup Pages - LGS, Unit 1
3. Technical Specifications Markup Pages - LGS, Unit 2
4. Summary of Example Surveillance Test Interval Evaluations
5. Regulatory Guide 1.200 PRA Adequacy Evaluation

cc:	Regional Administrator - NRC Region I	w/ attachments
	NRC Senior Resident Inspector - Limerick Generating Station	"
	NRC Project Manager, NRR - Limerick Generating Station	"
	NRC Project Manager - BWROG	"
	NRC Project Manager - RITS Task Force	"
	Director, Bureau of Radiation Protection - Pennsylvania Department of Environmental Protection	"

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ATTACHMENT 1

LICENSE AMENDMENT REQUEST

LIMERICK GENERATING STATION, UNITS 1 AND 2
DOCKET NOS. 50-352 AND 50-353

EVALUATION OF THE PROPOSED CHANGE

Subject: Relocation of Surveillance Test Intervals from the Technical Specifications to a Licensee-Controlled Program (Risk-Informed Initiative 5b)

1.0 DESCRIPTION

2.0 PROPOSED CHANGES

3.0 BACKGROUND

4.0 TECHNICAL ANALYSIS

5.0 REGULATORY ANALYSIS

6.0 ENVIRONMENTAL CONSIDERATION

7.0 REFERENCES

1.0 DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (Exelon), requests a change to the Technical Specifications (TS), Appendix A, of Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively.

The proposed change will relocate the surveillance test intervals (STIs) of various TS surveillance requirements from the TS to a licensee program controlled in accordance with the requirements of 10 CFR 50.59. Revisions to the STIs will be made in accordance with a new program, the Surveillance Frequency Control Program, which is being added to the Administrative Controls section of TS. The new program is predicated on NRC approval of a risk-informed process and methodology for control of changes to STIs being submitted separately from this request. A complete description of the proposed change is given in Section 2.0, "Proposed Changes," of this Attachment. Attachments 2 and 3 provide the marked-up TS pages indicating the proposed changes for LGS, Units 1 and 2, respectively.

NOTE: in the course of this and other associated attachments, the terms surveillance test interval, surveillance interval, interval, surveillance requirement frequency, surveillance frequency, and frequency may be used interchangeably.

Individual STIs will not be revised as part of this license amendment request (LAR); however, a summary of the results of several example STI evaluations using the proposed risk-informed methodology has been provided within Attachment 4. Once this LAR and the risk-informed process and methodology are approved by the NRC, future changes to the STIs will be evaluated in accordance with the licensee-controlled program, and the STIs may be revised, as appropriate, based on the evaluation results without prior NRC approval.

NOTE: various TS surveillance requirements, including in some cases their associated STIs, were established based on commitments to Regulatory Guides, or based on implementation of NRC-approved Licensing Topical Reports. Within the licensee-controlled program, the surveillance requirements themselves will not be changed and will continue to be performed in accordance with the applicable Regulatory Guide or Topical Report, as appropriate; however, associated STIs may be modified in accordance with the licensee-controlled program.

2.0 PROPOSED CHANGES

LGS has separate TS for Unit 1 and Unit 2, however, the proposed changes are identical for both units.

1. Revise Index, as appropriate, to reflect the TS changes proposed below.

2. Replace various STIs specified within individual surveillance requirements with a reference to the licensee-controlled program, e.g., with the words "in accordance with the Surveillance Frequency Control Program." The proposed change applies primarily to surveillances that are performed on a fixed periodicity (e.g., channel checks, channel functional tests, channel calibrations, logic system functional tests, etc.). Existing STIs that are not proposed to be relocated as part of this request are associated with surveillance requirements that:

(a) have no time component but are purely event driven, e.g., "prior to thermal power exceeding 40% of rated thermal power";
(b) are event driven but have a time component for performing the surveillance on a one time basis once the event occurs, e.g., "within 12 hours after completion of a thermal power increase of at least 15% of rated thermal power"; or
(c) reference an already established and approved licensee program rather than a specific interval, e.g., surveillance requirements that refer to Specification 4.0.5 (the Inservice Testing Program), or the Primary Containment Leakage Rate Testing Program.

NOTE: STIs that are event/time-based which involve a fixed periodicity for performing the surveillance once the event occurs, e.g., "at least once per 24 hours while greater than 25% of rated thermal power," are proposed to be relocated to the licensee-controlled program as part of this LAR.

3. Add a new TS Section 6.8.4.j, "Surveillance Frequency Control Program," which will describe the basic means for licensee control of surveillance frequencies within the licensee-controlled program.

4. Revise the TS Bases, as appropriate, relative to the proposed TS changes described above.

3.0 BACKGROUND

Since the mid-1980s, the NRC has been reviewing and granting improvements to TS based, at least in part, on probabilistic risk analysis insights. Some of these improvements have been proposed by the Nuclear Steam Supply System (NSSS) owners groups to apply to an entire class of plants. Many others have been proposed by individual licensees. Typically, the proposed improvements involved a relaxation of one or more allowed outage times (AOTs) or STIs in the TS.

In its July 22, 1993, final policy statement on TS improvements (Ref. 1), the Commission stated that it:

> ...expects that licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific PSA [*probabilistic safety analysis*] or risk survey and any available literature on risk insights and PSAs . . . Similarly, the NRC staff will also employ risk insights and PSAs in evaluating Technical Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements.

The Commission reiterated this point when it issued the revision to 10 CFR 50.36 in July 1995 (Ref. 2).

In August 1995, the NRC adopted a final policy statement on the use of probabilistic risk assessment (PRA) methods, which included the following regarding the expanded use of PRA (Ref. 3).

- The use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.

- PRA and associated analyses (e.g., sensitivity studies, uncertainty analyses, and importance measures) should be used in regulatory matters, where practical within the bounds of the state of the art, to reduce unnecessary conservatism associated with current regulatory requirements, regulatory guides, license commitments, and staff practices. Where appropriate, PRA should be used to support the proposal of additional regulatory requirements in accordance with 10 CFR 50.109 (Backfit Rule). Appropriate procedures for including PRA in the process for changing regulatory requirements should be developed and followed. It is, of course, understood that the intent of this policy is that existing rules and regulations shall be complied with unless these rules and regulations are revised.

- PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available for review.

- The Commission's safety goals for nuclear power plants and subsidiary numerical objectives are to be used with appropriate consideration of uncertainties in making regulatory judgments on need for proposing and backfitting new generic requirements on nuclear power plant licensees.

In its approval of the policy statement, the Commission articulated its expectation that implementation of the policy statement will improve the regulatory process in three areas: foremost, through safety decisionmaking enhanced by the use of PRA insights; through more efficient use of agency resources; and through a reduction in unnecessary burdens on licensees.

This LAR is being submitted as a pilot submittal in support of the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b, "Relocate Surveillance Test Intervals to Licensee Control." This LAR is predicated on NRC approval of a risk-informed process and methodology developed by the BWROG Risk Informed Technical Specifications (RITS) Committee in concert with the Nuclear Energy Institute (NEI) for control of changes to STIs associated with TS surveillance requirements. The details of this risk-informed process and methodology are being submitted separately to the NRC for review and approval as part of Technical Specification Task Force (TSTF) 425. Exelon requests approval of this LAR in conjunction with NRC approval of TSTF-425. In addition, in support of the proposed change, Attachment 5 provides an evaluation of the technical adequacy of the LGS PRA for this application relative to the guidance provided in NRC Regulatory Guide 1.200 (Ref. 4).

4.0 TECHNICAL ANALYSIS

The discussion below provides an overview of the approach for control of changes to STIs using the proposed risk-informed methodology. A summary of results of several example STI evaluations that were used to exercise the proposed process and methodology is provided in Attachment 4.

4.1 Overall Approach

The control of changes to the relocated STIs will be in accordance with the Surveillance Frequency Control Program. This program shall ensure that Surveillance Requirements specified in TS are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met. The program contains the following requirements:

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

b. changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI-04-10 (Ref. 5), and

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

The referenced document, NEI-04-10, provides a detailed description of the methodology to be followed when evaluating changes to STIs within the program, and is being submitted separately for NRC approval as part of TSTF-425.

The proposed approach uses existing Maintenance Rule implementation guidance (NUMARC 93-01, Rev. 3) (Ref. 6), risk categorization guidance originally developed for the proposed 10 CFR 50.69, "Option 2" rulemaking, (NEI-00-04) (Ref. 7), combined with elements of NRC Regulatory Guide 1.175 (Ref. 8), to develop risk-informed test intervals for structures, systems and components (SSCs) having TS surveillance test requirements. While originally developed to address test intervals for pump and valve testing required by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, the concepts of Regulatory Guide 1.175 are applicable to this initiative with minor modifications. In particular, this Regulatory Guide provides information relative to modeling the effect of the revised surveillance intervals in the PRA.

The methodology is also consistent with Regulatory Guides 1.174 (Ref. 9) and 1.177 (Ref. 10), and provides more specific guidelines to facilitate application by Licensees. Regulatory Guide 1.177 provides guidance for changing STIs and AOTs. However, for allowable risk changes associated with STI extensions, it refers to Regulatory Guide 1.174, which provides quantitative risk acceptance guidelines for changes to core damage frequency (CDF) and large early release frequency (LERF). Regulatory Guide 1.174 provides additional guidelines that have been adapted in the risk-informed methodology for controlling changes to STIs.

4.2 Key Safety Principles

Regulatory Guide 1.174 identifies five key safety principles to be met for all risk-informed applications and to be explicitly addressed in risk-informed plant program change applications.

1. **The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.**

   10 CFR 50.36(c) (Ref. 11) provides that TS will include items in the following categories:

   "(3) *Surveillance requirements.* Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and

components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met."

This change proposes to relocate various intervals for the performance of the above requirements to a licensee-controlled program using an NRC approved methodology for control of the surveillance intervals. The surveillance requirements themselves will remain in TS. This is consistent with other NRC approved TS changes in which the surveillance intervals are not under NRC control, such as surveillances that are performed in accordance with the Inservice Testing Program or the Primary Containment Leakage Rate Testing Program, where the STIs vary based on the past performance of the subject components. Thus, this proposed change meets criterion 1 above.

2. **The proposed change is consistent with the defense-in-depth philosophy.**

As described in Position 2.2.1.1 of Regulatory Guide 1.174, consistency with the defense-in-depth philosophy is maintained if:

- A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation.
- Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.
- System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers).
- Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.
- Independence of barriers is not degraded.
- Defenses against human errors are preserved.
- The intent of the General Design Criteria in 10 CFR Part 50, Appendix A is maintained.

These defense-in-depth objectives apply to all risk-informed applications, and for some of the issues involved (e.g., no over-reliance on programmatic activities and defense against human errors), it is fairly straightforward to apply them to this proposed change. The use of the multiple risk metrics of CDF and LERF and controlling their change resulting from the implementation of this initiative would maintain a balance between prevention of core damage, prevention of containment failure, and consequence mitigation. Redundancy, diversity, and independence of safety systems are considered as part of the risk categorization to ensure that these qualities are not adversely affected. Independence of barriers and defense against common cause failures are also considered in the categorization. The improved understanding of the relative importance of plant components to risk resulting from the development of this program promotes an improved overall understanding of how the SSCs contribute to the plant's defense-in-depth.

3. **The proposed change maintains sufficient safety margins.**

   Conformance with this principle is assured since Codes and Standards or alternatives approved for use by the NRC will still be met with the proposed change. Also, the safety analysis acceptance criteria in the licensing basis (e.g., Final Safety Analysis Report, supporting analyses, etc.) are met with the proposed change.

4. **When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.**

   Information obtained from the LGS PRA is used in two ways: first, to provide input to the categorization of SSCs into high safety significance (HSS) and low safety significance (LSS) groupings; and second, to assess the impact of the proposed change on CDF and LERF. The overall impact of the change is assessed and compared to the quantitative risk acceptance guidelines of Regulatory Guide 1.174, which is consistent with the intent of the Commission's Safety Goal Policy Statement.

   The PRA used to support this change, at a minimum, addresses CDF and LERF for power operation. External event risk and shutdown considerations will be addressed through quantitative or qualitative means.

   In addition, the technical adequacy of the LGS PRA was reviewed against the guidance provided in NRC Regulatory Guide 1.200. A summary of this review is provided in Attachment 5. Any identified gaps in the LGS PRA based on this review will be addressed, as appropriate, when applying the PRA to individual STI evaluations within the licensee program for controlling changes to STIs.

5. **The impact of the proposed change should be monitored using performance measurement strategies.**

   For HSS components (HSSCs), a performance monitoring strategy will be developed to provide confidence that the equipment performance is consistent with the considerations of the overall process, and is not degrading such that the analysis assumptions and Integrated Decisionmaking Panel judgments are no longer valid. The output of the performance monitoring will be periodically re-assessed, and appropriate adjustments made to the test intervals.

   LSS components (LSSCs) have been shown through a robust categorization process (NEI-00-04) to be of low risk significance. Changes to STIs for these SSCs will have a small effect on their performance, and thus will have a second order effect on risk. Because of this minimal risk impact, existing performance monitoring required by the Maintenance Rule is adequate for LSSC surveillance intervals.

4.3 STI Revision Process

A summary of the proposed risk-informed methodology is provided in Attachment 4.

4.4 Conclusion

The STIs will be relocated to a licensee-controlled program. Any future changes to the licensee program will be controlled by the 10CFR50.59 process. Specific changes to the relocated STIs

will be evaluated in accordance with the licensee-controlled program using the risk-informed process and methodology as approved by the NRC.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

Exelon has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. **Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?**

   Response: No. The proposed change involves the relocation of various surveillance test intervals from Technical Specifications (TS) to a licensee-controlled program and is administrative in nature. The proposed change does not involve the modification of any plant equipment or affect basic plant operation. The proposed change will have no impact on any safety related structures, systems or components. Surveillance test intervals are not assumed to be an initiator of any analyzed event, nor are they assumed in the mitigation of consequences of accidents. The surveillance requirements themselves will be maintained in TS along with the applicable Limiting Conditions for Operation (LCOs) and Action statements. The surveillances performed at the intervals specified in the licensee-controlled program will assure that the affected system or component function is maintained, that the facility operation is within the Safety Limits, and that the LCOs are met.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. **Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?**

   Response: No. The proposed change does not involve any physical alteration of plant equipment and does not change the method by which any safety-related system performs its function or is tested. As such, no new or different types of equipment will be installed, and the basic operation of installed equipment is unchanged. The methods governing plant operation and testing remain consistent with current safety analysis assumptions.

   Therefore, the proposed change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. **Does the proposed change involve a significant reduction in a margin of safety?**

   Response: No. The proposed change is administrative in nature, does not negate any existing requirement, and does not adversely affect existing plant safety margins or the reliability of the equipment assumed to operate in the safety analysis. As such, there are no changes being made to safety analysis assumptions, safety limits or safety system settings that would adversely affect plant safety as a result of the proposed

change. Margins of safety are unaffected by relocation of the surveillance test intervals to a licensee-controlled program.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Exelon concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

Section 182a of the Atomic Energy Act of 1954, as amended (the Act) (Ref. 12) requires applicants for nuclear power plant operating licenses to include the TS as part of the license. The Commission's regulatory requirements related to the content for the TS are set forth in 10 CFR 50.36. That regulation requires that the TS include items in eight specific categories. The categories are: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; (5) administrative controls; (6) decommissioning; (7) initial notification; and (8) written reports. However, the regulation does not specify the particular requirements to be included in a plant's TS.

The proposed change relocates the intervals for the performance of various surveillance requirements from TS to a licensee-controlled program using an NRC approved methodology for control of the surveillance intervals once in the licensee program. The surveillance requirements themselves will remain in TS. The proposed change is consistent with the TS Section 4.0.5 requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components. In several instances, the LGS TS do not specify a particular surveillance interval but rather state: "when tested pursuant to Specification 4.0.5." TS Section 4.0.5 references Section XI of the ASME Boiler and Pressure Vessel Code for the surveillance intervals. The surveillance intervals are based on the plant's Inservice Testing (IST) Program which implements the ASME Code. Within the IST program, the actual surveillance intervals vary based on the performance of the individual components. In other instances, the TS again do not specify a particular surveillance interval but instead require that the surveillance be performed "in accordance with the Primary Containment Leakage Rate Testing Program." The Primary Containment Leakage Rate Testing Program references 10 CFR 50, Appendix J, Option B, which allows performance based testing. The testing interval varies based on the past performance of the subject components. In these circumstances, the LGS TS do not specify an explicit surveillance interval.

The proposed TS changes are administrative in nature. Relocation of the STIs from the TS to a licensee-controlled program does not affect the plant design, hardware, or system operation and will not affect the ability of the plant to perform its design function in mitigating the consequences of a postulated design basis accident. Therefore, the proposed change does not adversely affect nuclear safety or plant operations.

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.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement, or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. NRC Final Policy Statement, 10 CFR Part 50, "Final Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors," *Federal Register*, 58 FR 39132, dated July 22, 1993.

2. NRC Final Rule, 10 CFR Part 50, "Technical Specifications," *Federal Register*, 60 FR 36953, dated July 19, 1995.

3. USNRC, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," *Federal Register*, Vol. 60, p. 42622, August 16, 1995.

4. Regulatory Guide 1.200 For Trial Use (Draft was issued as DG-1122), "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-informed Activities," February 2004

5. NEI-04-10 (Draft), "Risk Informed Method for Control of Surveillance Frequencies," June 2004

6. NUMARC 93-01, Rev. 3, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," July 2000

7. NEI 00-04 (Draft), "10 CFR 50.69 SSC Categorization Guideline," June 2002

8. Regulatory Guide 1.175, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Inservice Testing," August 1998

9. Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998

10. Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specification," August 1998

11. 10 CFR 50.36, "Technical Specifications"

12. Section 182a of the Atomic Energy Act of 1954 (Act), as amended (42 U.S.C. 2232)

ATTACHMENT 2

LICENSE AMENDMENT REQUEST

LIMERICK GENERATING STATION, UNITS 1 AND 2
DOCKET NOS. 50-352 AND 50-353

RELOCATION OF SURVEILLANCE TEST INTERVALS FROM THE TECHNICAL SPECIFICATIONS TO A LICENSEE-CONTROLLED PROGRAM

UNIT 1 MARKED-UP TECHNICAL SPECIFICATIONS AND BASES PAGES FOR THE PROPOSED CHANGE

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3/4 3-31	3/4 4-5	3/4 6-52	3/4 9-3	B 3/4 5-2
3/4 3-32	3/4 4-7	3/4 6-53	3/4 9-4	B 3/4 6-2
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3/4 3-41	3/4 4-10	3/4 6-56	3/4 9-7	B 3/4 6-5
3/4 3-42	3/4 4-13	3/4 6-57	3/4 9-10	B 3/4 8-2
3/4 3-45	3/4 4-17	3/4 6-58	3/4 9-11	B 3/4 8-2a
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3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

2. If the inoperable control rod(s) is inserted, within 1 hour disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

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

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

d. With one or more scram discharge volume (SDV) vent or drain lines with one valve inoperable, restore the inoperable valve(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

e. With one or more SDV vent or drain lines with both valves inoperable, isolate the associated line within 8 hours **** or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ Verifying each valve to be open,* and

b. ~~At least once per 92 days~~ Cycling each valve through at least one complete cycle of full travel.

---

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

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

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

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

SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.2 When above the preset power level of the RWM, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program, and

b. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6, and 4.1.3.7.

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

a. The scram discharge volume drain and vent valves OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves;

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

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume scram and control rod block level instrumentation ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 5, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the maximum scram insertion time of one or more control rods exceeding 7 seconds:

   1. Declare the control rod(s) with the slow insertion time inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2c. at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

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

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement and, during single control rod scram time tests, the control rod drive pumps shall be isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER with reactor coolant pressure greater than or equal to 950 psig, following CORE ALTERATIONS or after a reactor shutdown that is greater than 120 days.

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods in accordance with either "1" or "2" as follows:

   1.a Specifically affected individual control rods shall be scram time tested at zero reactor coolant pressure and the scram insertion time from the fully withdrawn position to notch position 05 shall not exceed 2.0 seconds, and

   1.b Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure prior to exceeding 40% of RATED THERMAL POWER.

   2. Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure.

c. For at least 10% of the control rods, with reactor coolant pressure greater than or equal to 950 psig, on a rotating basis, and ~~at least once per 120 days of POWER OPERATION~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

2. With more than one withdrawn control rod with the associated scram accumulator inoperable or no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position.

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program by verifying that the indicated pressure is greater than or equal to 955 psig unless the control rod is inserted and disarmed or scrammed.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program that the position of each control rod is indicated,

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

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

ROD BLOCK MONITOR

LIMITING CONDITION FOR OPERATION

3.1.4.3 Both rod block monitor (RBM) channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER and less than 90% of RATED THERMAL POWER with MCPR less than 1.70, or THERMAL POWER greater than or equal to 90% of rated with MCPR less than 1.40.

ACTION:

a. With one RBM channel inoperable:

   1. Verify that the reactor is not operating on a LIMITING CONTROL ROD PATTERN, and

   2. Restore the inoperable RBM channel to OPERABLE status within 24 hours.

   Otherwise, place the inoperable rod block monitor channel in the tripped condition within the next hour.

b. With both RBM channels inoperable, place at least one inoperable rod block monitor channel in the tripped condition within 1 hour.

SURVEILLANCE REQUIREMENTS

4.1.4.3 Each of the above required RBM channels shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION ~~at the frequencies and~~ for the OPERATIONAL CONDITIONS specified in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

b. CHANNEL FUNCTIONAL TEST prior to control rod withdrawal when the reactor is operating on a LIMITING CONTROL ROD PATTERN.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system consisting of a minimum of two pumps and corresponding flow paths, shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With only one pump and corresponding explosive valve OPERABLE, restore one inoperable pump and corresponding explosive valve to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

2. With standby liquid control system otherwise inoperable, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

2. The available volume of sodium pentaborate solution is at least 3160 gallons.

3. The temperature of the pump suction piping is within the limits of Figure 3.1.5-1 for the most recent concentration analysis.

SURVEILLANCE REQUIREMENTS (Continued)

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying the continuity of the explosive charge.

2. Determining by chemical analysis and calculation* that the available weight of sodium pentaborate is greater than or equal to 3754 lbs; the concentration of sodium pentaborate in solution is less than or equal to 13.8% and within the limits of Figure 3.1.5-1 and; the following equation is satisfied:

$$\frac{C}{13\%\ \text{wt.}} \times \frac{E}{29\ \text{atom}\ \%} \times \frac{Q}{86\ \text{gpm}} \geq 1$$

where

C = Sodium pentaborate solution (% by weight)
Q = Two pump flowrate, as determined per surveillance requirement 4.1.5.c.
E = Boron 10 enrichment (atom % Boron 10)

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

c. Demonstrating that, when tested pursuant to Specification 4.0.5, the minimum flow requirement of 41.2 gpm per pump at a pressure of greater than or equal to 1230 ± 25 psig is met.

d. ~~At least once per 24 months during shutdown~~ In accordance with the Surveillance Frequency Control Program by:

1. Initiating at least one of the standby liquid control system loops, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of the batch success-fully fired. All injection loops shall be tested in 3 operating cycles.

2. Verify all heat-treated piping between storage tank and pump suction is unblocked.**

e. Prior to addition of Boron to storage tank verify sodium pentaborate enrichment to be added is ≥ 29 atom % Boron 10.

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* This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after water or boron addition or solution temperature is restored.

** This test shall also be performed whenever suction piping temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after solution temperature is restored.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of axial location and AVERAGE PLANAR EXPOSURE shall be within limits based on applicable APLHGR limit values which have been determined by approved methodology for the respective fuel and lattice types. When hand calculations are required, the APLHGR for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limiting value for the most limiting lattice (excluding natural uranium) as shown in the CORE OPERATING LIMITS REPORT (COLR). During operation, the APLHGR for each fuel type shall not exceed the above values multiplied by the appropriate reduction factors for power and flow as defined in the COLR.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limiting value, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limiting value

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) EOC-RPT inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

c. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) main turbine bypass valve inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2a, and during reactor startups prior to control rod scram time tests in accordance with Specification 4.1.3.2.b.1.b, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit, including application of the MCPR(P) and MCPR(F) factors as determined from the CORE OPERATING LIMITS REPORT.

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) for each fuel type shall not exceed the value in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGRs shall be determined to be equal to or less than the limit:

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, and 2.e. Functions 2.a, 2.b, 2.c, and 2.d do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-of-4 voter logic in the voter channels.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific reactor trip system.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK(m)	CHANNEL FUNCTIONAL TEST(m)	CHANNEL CALIBRATION(a)(m)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	~~S~~(b)	~~W~~	~~R~~	2
	~~S~~	~~W~~(j)	~~R~~	3(i), 4(i), 5(i)
b. Inoperative	N.A.	~~W~~(j)	N.A.	2, 3(i), 4(i), 5(i)
2. Average Power Range Monitor(f):				
a. Neutron Flux - Upscale (Setdown)	~~D~~(b)	~~SA~~(l)	~~R~~	2
b. Simulated Thermal Power - Upscale	~~D~~	~~SA~~(e)	~~W~~(d), ~~R~~(g)	1
c. Neutron Flux - Upscale	~~D~~	~~SA~~	~~W~~(d)~~, R~~	1
d. Inoperative	N.A.	~~SA~~	N.A.	1, 2
e. 2-Out-Of-4 Voter	~~D~~	~~SA~~	N.A.	1, 2
3. Reactor Vessel Steam Dome Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2(h)
4. Reactor Vessel Water Level-Low, Level 3	~~S~~	~~Q~~	~~R~~	1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.	~~Q~~	~~R~~	1
6. DELETED	~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~
7. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	~~S~~	~~Q~~	~~R~~	1, 2, 5(i)
b. Float Switch	N.A.	~~Q~~	~~R~~	1, 2, 5(i)

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK(m)	CHANNEL FUNCTIONAL TEST(m)	CHANNEL CALIBRATION(a)(m)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Turbine Stop Valve - Closure	N.A.	~~Q~~	~~R~~	1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.	~~Q~~	~~R~~	1
11. Reactor Mode Switch Shutdown Position	N.A.	~~R~~	N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.	~~W~~	N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.
(c) DELETED
(d) ~~This~~ The more frequent calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.
(e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.
(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH).
(g) The less frequent calibration includes the flow input function.
(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.
(k) DELETED
(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.
(m) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operations of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.

** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
2) Low, Low, Low - Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. DELETED	~~DELETED~~	~~DELETED~~	~~DELETED~~	DELETED
c. Main Steam Line Pressure - Low	~~S~~	~~Q~~	~~R~~	1
d. Main Steam Line Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. Condenser Vacuum - Low	~~S~~	~~Q~~	~~R~~	1, 2**, 3**
f. Outboard MSIV Room Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
h. Manual Initiation	N.A.	~~R~~	N.A.	1. 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level## Low - Level 3	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. RWCS Area Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. SLCS Initiation	N.A.	~~R~~	N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. HPCI Steam Supply Pressure, Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. HPCI Equipment Room Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. HPCI Equipment Room Δ Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. HPCI Pipe Routing Area Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3
h. HPCI Steam Line Δ Pressure Timer	N.A.	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. RCIC Steam Supply Pressure - Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. RCIC Equipment Room Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. RCIC Equipment Room Δ Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. RCIC Pipe Routing Area Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3
h. RCIC Steam Line Δ Pressure Timer	N.A.	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
2) Low, Low, Low - Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Drywell Pressure## - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. North Stack Effluent Radiation - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. Deleted				
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.	~~M~~	~~Q~~	1, 2, 3
j. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2	S	Q	R	1, 2, 3
b. Drywell Pressure## - High	S	Q	R	1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	S	Q	R	1, 2, 3
e. Deleted				
f. Deleted				
g. Reactor Enclosure Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. Refueling Area Manual Initiation	N.A.	R	N.A.	*

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

*Required when (1) handling irradiated fuel in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

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

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

c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days, provided that the HPCI and RCIC systems are OPERABLE.

   2. 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.3.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Reactor Vessel Pressure - Low	~~S~~	~~Q~~	~~R~~	1, 2, 3, 4*, 5*
d. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Reactor Vessel Pressure - Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. Injection Valve Differential Pressure - Low (Permissive)	~~S~~	~~Q~~	~~R~~	1, 2, 3, 4*, 5*
e. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM***				
a. Reactor Vessel Water Level - Low Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Condensate Storage Tank Level - Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. Suppression Pool Water Level - High	~~S~~	~~Q~~	~~E~~	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

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

* When the system is required to be OPERABLE per Specification 3.5.2.

** Required OPERABLE when ESF equipment is required to be OPERABLE.

*** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Loss of Voltage Relay 127-11X is not field setable.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

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

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 24 hours.

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

   1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within 24 hours, or, if this action will initiate a pump trip, declare the trip system inoperable.

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

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

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1.Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.1-1~~ specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.4.1-1~~

~~ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION~~

~~SURVEILLANCE REQUIREMENTS~~

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

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SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.2.1-1~~ specified in the Surveillance Frequency Control Program.

4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested ~~at least once per 48 months~~ in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured ~~at least once per 60 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.4.2.1-1~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS~~

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

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~~* Including trip system logic testing.~~

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each of the required RCIC system actuation instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.5.1-1~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.5.1-1. CHANNEL CHECK and CHANNEL CALIBRATION are not required for manual initiation.

4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.5.1-1~~

~~REACTOR CORE ISOLATION SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

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

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3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint** less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition, provided at least one other operable channel in the same trip system is monitoring that parameter.

**The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 4.3.6-1
CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(h)	CHANNEL FUNCTIONAL TEST(h)	CHANNEL CALIBRATION(a)(h)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	~~Q~~(c)	~~R~~	1*
b. Inoperative	N.A.	~~Q~~(c)	N.A.	1*
c. Downscale	N.A.	~~Q~~(c)	~~R~~	1*
2. APRM				
a. Simulated Thermal Power-Upscale	N.A.	~~SA~~	~~R~~	1
b. Inoperative	N.A.	~~SA~~	N.A.	1, 2
c. Neutron Flux - Downscale	N.A.	~~SA~~	~~R~~	1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.	~~SA~~	~~R~~	2
e. Recirculation Flow - Upscale	N.A.	~~SA~~	~~R~~	1
f. LPRM Low Count	N.A.	~~SA~~	~~R~~	1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	~~M~~[d](e)~~,W~~[f]	N.A.	2, 5
b. Upscale	N.A.	~~M~~[d](e)~~,W~~[f]	~~R~~	2, 5
c. Inoperative	N.A.	~~M~~[d](e)~~,W~~[f]	N.A.	2, 5
d. Downscale	N.A.	~~M~~[d](e)~~,W~~[f]	~~R~~	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.	~~W~~	N.A.	2, 5
b. Upscale	N.A.	~~W~~	~~R~~	2, 5
c. Inoperative	N.A.	~~W~~	N.A.	2, 5
d. Downscale	N.A.	~~W~~	~~R~~	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.	~~Q~~	~~R~~	1, 2, 5**
6. DELETED	DELETED	DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	~~R~~(g)	N.A.	3, 4

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

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

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

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

*** Deleted.

(d) Deleted ~~When in OPERATIONAL CONDITION 2.~~

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) Deleted ~~When in OPERATIONAL CONDITION 5.~~

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

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

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

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

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

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK(c)	CHANNEL FUNCTIONAL TEST(c)	CHANNEL CALIBRATION(c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	S	Q	R	1, 2, 3, 5 and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	S	M	R	(a)
b. Control Room Direct Radiation Monitor	S	M	R	At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor	S	M	R(b)	At All Times

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When irradiated fuel is being handled in the secondary containment.

(a) With fuel in the spent fuel storage pool.

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

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

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

b. With the number of OPERABLE remote shutdown system controls less than required in Table 3.3.7.4-1, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

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

4.3.7.4.2 Each of the above remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

*Control is not required to be transferred to perform the CHANNEL CHECK.

~~TABLE 4.3.7.4-1~~

~~REMOTE SHUTDOWN SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~INSTRUMENT~~	~~CHANNEL CHECK *~~	~~CHANNEL CALIBRATION~~
~~1. Reactor Vessel Pressure~~	~~M~~	~~R~~
~~2. Reactor Vessel Water Level~~	~~M~~	~~R~~
~~3. Safety/Relief Valve Position, 3 valves~~	~~M~~	~~NA~~
~~4. Suppression Chamber Water Level~~	~~M~~	~~R~~
~~5. Suppression Chamber Water Temperature~~	~~M~~	~~R~~
~~6. Drywell Pressure~~	~~M~~	~~R~~
~~7. Drywell Temperature~~	~~M~~	~~R~~
~~8. RHR System Flow~~	~~M~~	~~R~~
~~9. RHR Service Water Pump Discharge Pressure~~	~~M~~	~~R~~
~~10. RHR Heat Exchanger Service Water Outlet Pressure~~	~~M~~	~~R~~
~~11. RCIC System Flow~~	~~M~~	~~R~~
~~12. RCIC Turbine Speed~~	~~M~~	~~R~~
~~13. Emergency Service Water Pump Discharge Pressure~~	~~M~~	~~R~~
~~14. Condensate Storage Tank Level~~	~~M~~	~~R~~
~~15. RHR Heat Exchanger Bypass Valve (HV51-1F048A) Position Indication (0 - 100%)~~	~~M~~	~~R~~
~~16. RCIC Turbine Tripped Indication~~	~~M~~	~~R~~
~~17. RCIC Turbine Bearing Oil Pressure Low Indication~~	~~M~~	~~R~~
~~18. RCIC LP Bearing Oil Temperature High Indication~~	~~M~~	~~R~~
~~19. RHR Heat Exchanger Discharge Line High Radiation Indication~~	~~M~~	~~R~~

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~~*Control is not required to be transferred to perform this CHANNEL CHECK.~~

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies ~~shown~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.5-1.

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK(a)	CHANNEL CALIBRATION(a)
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Chamber Water Level	M	R
4. Suppression Chamber Water Temperature	M	R
5. Suppression Chamber Air Temperature	M	R
6. Primary Containment Pressure	M	R
7. Drywell Air Temperature	M	R
8. Drywell Oxygen Concentration Analyzer	M	Q#
9. Drywell Hydrogen Concentration Analyzer	M	Q*
10. Safety/Relief Valve Position Indicators	M	R
11. Primary Containment Post LOCA Radiation Monitors	M	R**
12. North Stack Wide Range Accident Monitor***	M	R
13. Neutron Flux	M	R

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

*Using calibration gas containing:
Seven volume percent hydrogen, balance nitrogen.

**CHANNEL CALIBRATION shall 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.

***High range noble gas monitors.

#Using calibration gas containing:
Seven volume percent oxygen, balance nitrogen.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

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

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

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

ACTION:

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

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

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

a. Performance of a:

1. CHANNEL CHECK ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

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

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

2. CHANNEL CALIBRATION** ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3.0 cps*** with the detector fully inserted.

*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.

INSTRUMENTATION

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.1 Two independent chlorine detection system subsystems shall be OPERABLE with their alarm and trip setpoints adjusted to actuate at a chlorine concentration of less than or equal to 0.5 ppm

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detection subsystem inoperable, restore the inoperable detection system to OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of at least one control room emergency filtration system subsystem in the chlorine isolation mode of operation.

b. With both chlorine detection subsystems inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration system subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.1 Each of the above required chlorine detection system subsystems shall be demonstrated OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

~~a. CHANNEL CHECK at least once per 12 hours,~~

~~b. CHANNEL FUNCTIONAL TEST at least once per 92 days, and~~

~~c. CHANNEL CALIBRATION at least once per 24 months.~~

INSTRUMENTATION

TOXIC GAS DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.2 Three independent toxic gas detection system subsystems shall be OPERABLE with their alarm setpoints adjusted to actuate at a toxic gas concentration of less than or equal to:

CHEMICAL	MONITOR SET POINT (ppm)
Ammonia	25
Ethylene Oxide	50
Formaldehyde	5
Vinyl Chloride	10
Phosgene	0.4

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one toxic gas detection subsystem inoperable, place the inoperable subsystem in the tripped condition within 24 hours.

b. With two toxic gas detection system subsystems inoperable, place one inoperable subsystem in the tripped condition within 1 hour, restore one inoperable detection subsystem to OPERABLE status within 7 days, or initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

c. With three toxic gas detection subsystems inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.2 Each of the above required toxic gas detection system subsystems shall be demonstrated OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

~~a. CHANNEL CHECK at least once per 12 hours,~~

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

~~c. CHANNEL CALIBRATION at least once per 24 months.~~

OFFGAS GAS MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.12 The offgas monitoring instrumentation channels shown in Table 3.3.7.12-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specifications 3.11.2.5 and 3.11.2.6 respectively, are not exceeded.

APPLICABILITY: As shown in Table 3.3.7.12-1

ACTION:

a. With an offgas monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Specification, declare the channel inoperable, and take the ACTION shown in Table 3.3.7.12-1.

b. With less than the minimum number of offgas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.12-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or explain why this inoperability was not corrected in a timely manner in the next Annual Radioactive Effluent Release Report.

c. The provisions of Specifications 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each offgas monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies ~~shown~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.12-1.

TABLE 4.3.7.12-1

OFFGAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK(5)	SOURCE CHECK(5)	CHANNEL CALIBRATION(5)	CHANNEL FUNCTIONAL TEST(5)	MODES IN WHICH SURVEILLANCE IS REQUIRED
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N.A.	Q(3)	M	**
2. (Deleted)					
3. (Deleted)					
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR (STEAM JET AIR EJECTOR)					
a. Noble gas activity monitor	D	M	R(2)	Q(1)	**
5. (Deleted)					

TABLE 4.3.7.12-1 (Continued)

TABLE NOTATIONS

* (Deleted)

** During operation of the main condenser steam jet air ejector and offgas treatment system.

*** (Deleted)

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exist:

1. Instrument indicates measured levels above the alarm/trip setpoint.

2. Circuit failure.

3. Instrument indicates a downscale failure.

4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Institute of Standards and Technology (NIST), previously National Bureau of Standards, or using standards that have been obtained from suppliers that participate in measurement assurance activities with NIST. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(3) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. 0.0 volume percent hydrogen, balance nitrogen, and

2. 4 volume percent hydrogen, balance nitrogen

(4) (Deleted)

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

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

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

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

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

SURVEILLANCE REQUIREMENTS

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

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

~~TABLE 4.3.9.1-1~~

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

~~TRIP FUNCTION~~	~~CHANNEL CHECK~~	~~CHANNEL FUNCTIONAL TEST~~	~~CHANNEL CALIBRATION~~	~~OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED~~
~~1. Reactor Vessel Water Level High, Level 8~~	~~D~~	~~Q~~	~~R~~	~~1*~~

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~~* With Thermal Power greater than or equal to 25% of Rated Thermal Power.~~

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 DELETED

4.4.1.1.2 DELETED

4.4.1.1.3 Establish a baseline APRM and LPRM** neutron flux noise value within the regions for which monitoring is required (Specification 3.4.1.1, ACTION c) within 2 hours of entering the region for which monitoring is required unless baselining has previously been performed in the region since the last refueling outage.

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

a. Reactor THERMAL POWER is ≤ 76.2% of RATED THERMAL POWER,

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

c. The speed of the operating recirculation pump is ≤ 90% of rated pump speed.

d. Core flow is greater than 39% when THERMAL POWER is within the restricted zone of Figure 3.4.1.1-1.

4.4.1.1.5 With one reactor coolant system recirculation loop not in operation, within 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 30% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow.

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

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

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

The differential temperature requirements of Specification 4.4.1.1.5b. and c. do not apply when the loop not in operation is isolated from the reactor pressure vessel.

**Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. During two recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program while greater than 25% of RATED THERMAL POWER by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when both recirculation loop indicated flows are in compliance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established* pump speed-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established* patterns by more than 10%.

*To be determined from the startup test program data.

SURVEILLANCE REQUIREMENTS (Continued)

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

1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established* pump speed-loop flow characteristics.

2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from single recirculation loop flow measurements.

3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* single recirculation loop patterns by more than 10%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 25% of RATED THERMAL POWER and upon entering single recirculation loop operation.

*To be determined from the startup test program data.

RECIRCULATION PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of each other with core flow greater than or equal to 70% of rated core flow.

b. 10% of each other with core flow less than 70% of rated core flow.

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

ACTION:

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

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

b. Shutdown one of the recirculation loops within the next 8 hours and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

*See Special Test Exception 3.10.4.

3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of at least 12 of the following reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings:*#

4	safety/relief valves @ 1170 psig ±3%
5	safety/relief valves @ 1180 psig ±3%
5	safety/relief valves @ 1190 psig ±3%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the safety valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. DELETED

c. With one or more safety/relief valve acoustic monitors inoperable, restore the inoperable acoustic monitors to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be 0.20 of the full open noise level## by performance of a:

a. CHANNEL FUNCTIONAL TEST ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program, and a
b. CHANNEL CALIBRATION ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program **.

4.4.2.2 At least 1/2 of the safety relief valves shall be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, and they shall be rotated such that all 14 safety relief valves are removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 54 months~~ in accordance with the Surveillance Frequency Control Program. All safety valves will be recertification tested to meet a ±1% tolerance prior to returning the valves to service.

---

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

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

\# Up to 2 inoperable valves may be replaced with spare OPERABLE valves with lower setpoints until the next refueling.

Initial setting shall be in accordance with the manufacturer's recommendation. Adjustment to the valve full open noise level shall be accomplished during the startup test program.

ACTIONS:

F. With any other two or more leak detection systems inoperable other than ACTION E above OR with required Actions and associated Completion Time of ACTIONS A, B, C, D or E not met, be in HOT SHUTDOWN within 12 hours AND in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

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

a. Perform a CHANNEL CHECK of the primary containment atmosphere gaseous radioactivity monitoring system ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

b. Perform a CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

c. Perform a CHANNEL CALIBRATION of required leakage detection instrumentation ~~at least one per 24 months~~ in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

d. Monitor primary containment pressures ~~once per 12 hours~~ AND ~~monitor~~ primary containment temperature ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

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

a. Monitoring the primary containment atmospheric gaseous radioactivity ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate ~~at least once per eight (8) hours~~ in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

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

a. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program, and

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

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

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the allowable values in Table 3.4.3.2-1 by performance of a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

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

~~b. CHANNEL CALIBRATION at least once per 24 months.~~

SURVEILLANCE REQUIREMENTS

4.4.4 The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant for:

1. Chlorides ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~a) 72 hours, and~~

~~b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.~~

2. Conductivity ~~at least once per 72 hours~~ in accordance with the Surveillance Frequency Control Program.

3. pH ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~a) 72 hours, and~~

~~b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.~~

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable for up to 31 days, obtaining an in-line conductivity measurement ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~1. 4 hours in OPERATIONAL CONDITIONS 1, 2, and 3, and~~

~~2. 24 hours at all other times.~~

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~1. 7 days, and~~

~~2. 24 hours whenever conductivity is greater than the limit in in Table 3.4.4-1.~~

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

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

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

**Until the specific activity of the primary coolant system is restored to within its limits.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

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

a. A maximum heatup of 100°F in any 1-hour period,

b. A maximum cooldown of 100°F in any 1-hour period,

c. A maximum temperature change of less than or equal to 20°F in any 1-hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange temperature greater than or equal to 80°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figure 3.4.6.1-1 curve A, B, or C as applicable, ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curve C within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program during system heatup.

4.4.6.1.3 DELETED

4.4.6.1.4 DELETED

4.4.6.1.5 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 80°F:

a. In OPERATIONAL CONDITION 4 in accordance with the Surveillance Frequency Control Program, ~~when reactor coolant system temperature is:~~

~~1. ≤ 100°F, at least once per 12 hours.~~

~~2. ≤ 90°F, at least once per 30 minutes.~~

b. Within 30 minutes prior to and ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program during tensioning of the reactor vessel head bolting studs.

REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1053 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1053 psig, reduce the pressure to less than 1053 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1053 psig ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

*Not applicable during anticipated transients.

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two (2) independent RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

Each independent RHR shutdown cooling subsystem shall consist of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger, not common to the two (2) independent subsystems.

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

ACTION:

a. With less than the above required independent RHR shutdown cooling subsystems OPERABLE, immediately initiate corrective action to return the required independent subsystems to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, verify the availability of at least one alternate method capable of decay heat removal for each inoperable independent RHR shutdown cooling subsystem. Be in at least COLD SHUTDOWN within 24 hours.****

b. With no independent RHR shutdown cooling subsystem in operation, immediately initiate corrective action to return at least one (1) independent subsystem to operation as soon as possible. Within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one independent RHR shutdown cooling subsystem or alternate method shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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*One independent RHR shutdown cooling subsystem may be inoperable for up to 2 hours for surveillance testing provided the other independent subsystem is OPERABLE and in operation.

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

***The independent RHR shutdown cooling subsystem may be removed from operation during hydrostatic testing.

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

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION: #

a. With one (1) or two (2) RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.

b. With no RHR shutdown cooling subsystems in operation and no recirculation pump in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulating by an alternate method; and

   2. Once per hour monitor reactor coolant temperature and pressure.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one (1) RHR shutdown cooling subsystem or recirculation pump is operating or an alternate method shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up two (2) hours per eight (8) hour period.

** One (1) RHR shutdown cooling subsystem may be inoperable for up to two (2) hours for the performance of Surveillances.

*** The shutdown cooling subsystem may be removed from operation during hydrostatic testing.

\# Separate Action entry is allowed for each shutdown cooling subsystem.

SURVEILLANCE REQUIREMENTS

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

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

1. For the CSS, the LPCI system, and the HPCI system:

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

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

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

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

4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.

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

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

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

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

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

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

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

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

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

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid.

d. For the ADS:

1. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

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

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

   c) DELETED

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS

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

4.5.2.2 The core spray system shall be determined OPERABLE ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2a.2.b).

*One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying the water level to be greater than or equal to the required limit at the frequency specified in the Surveillance Frequency Control Program.~~, as applicable:~~

~~a. 22'0" at least once per 24 hours.~~

~~b. 16'0" at least once per 12 hours.~~

4.5.3.2 With the suppression chamber level less than the ~~above~~ required limit or drained in OPERATIONAL CONDITION 4 or 5*, ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program:

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

b. Verify footnote conditions * to be satisfied.

*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

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

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

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

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

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* See Special Test Exception 3.10.1

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

SURVEILLANCE REQUIREMENTS

4.6.1.3 The primary containment air lock shall be demonstrated OPERABLE:

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

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

c. ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program by verifying that only one door in the air lock can be opened at a time.***

*** Except that the airlock doors need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the airlock doors' interlock is tested within 8 hours after the primary containment has been deinerted and provided the shield door to the airlock is maintained locked closed.

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -1.0 and +2.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 145°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell average air temperature greater than 145°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the volumetric average of the temperatures at the following locations and shall be determined to be within the limit ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program:

	Approximate Elevation	Number of Installed Sensors*
a.	330'	3
b.	320'	3
c.	260'	3
d.	248'	6

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

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber purge system may be in operation with the supply and exhaust isolation valves in one supply line and one exhaust line open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With a drywell and/or suppression chamber purge supply and/or exhaust isolation valve open, except as permitted above, close the valve(s) within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8 ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program, verify each primary containment purge valve [18" or 24"] is closed.*, **

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* Only required to be met in OPERATIONAL CONDITIONS 1, 2 and 3.

** Not required to be met when the primary containment purge valves are open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require these valves to be open.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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

c. With only one suppression chamber water level indicator OPERABLE and/or with less than eight suppression pool water temperature indicators, one in each of the eight locations OPERABLE, restore the inoperable indicator(s) to OPERABLE status within 7 days or verify suppression chamber water level and/or temperature to be within the limits at least once per 12 hours.

d. With no suppression chamber water level indicators OPERABLE and/or with less than seven suppression pool water temperature indicators covering at least seven locations OPERABLE, restore at least one water level indicator and at least seven water temperature indicators to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

b. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program by verifying the suppression chamber average water temperature to be less than or equal to 95°F, except:

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

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

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

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER 12 hours after suppression chamber average water temperature has exceeded 95°F for more than 24 hours.

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

SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least 8 suppression pool water temperature indicators in at least 8 locations, OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the temperature alarm setpoint for:

~~1. CHANNEL CHECK at least once per 24 hours.~~
~~2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and~~
~~3. CHANNEL CALIBRATION at least once per 24 months,~~
~~with the temperature alarm setpoint for:~~

1. High water temperature:

   a) First setpoint ≤ 95°F

   b) Second setpoint ≤ 105°F

   c) Third setpoint ≤ 110°F

   d) Fourth setpoint ≤ 120°F

d. By verifying at least two suppression chamber water level indicators OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the water level alarm setpoint for high water level ≤ 24'1-1/2".

~~1. CHANNEL CHECK at least once per 24 hours,~~
~~2. CHANNEL FUNCTIONAL TEST at least once per 92 days, and~~
~~3. CHANNEL CALIBRATION at least once per 24* months,~~
~~with the water level alarm setpoint for high water level ≤ 24'1-1/2"~~

e. Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

f. By conducting a leakage test on the drywell-to-suppression chamber vacuum breakers at a differential pressure of at least 4.0 psi and verifying that the total leakage area $A/\sqrt{k}$ contributed by all vacuum breakers is less than or equal to 24% of the specified limit and the leakage area for an individual set of vacuum breakers is less than or equal to 12% of the specified limit. The vacuum breaker leakage test shall be conducted during each refueling outage for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted.

~~* The CHANNEL CALIBRATION for level transmitters LT-55-1N062B, -1N062F shall be performed at least once per 18 months.~~

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

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

a. One OPERABLE RHR pump, and

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 500 gpm on recirculation flow through the RHR heat exchanger and the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

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

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

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

a. One OPERABLE RHR pump, and

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 10,000 gpm on recirculation flow through the flow path including the RHR heat exchanger and its associated closed bypass valve, the suppression pool and the full flow test line when tested pursuant to Specification 4.0.5.

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

SURVEILLANCE REQUIREMENTS

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

4.6.3.2 Each primary containment automatic isolation valve shall be demonstrated OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

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

4.6.3.4 A representative sample of reactor instrumentation line excess flow check valves shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program, ~~at least once per 24 months such that each valve is tested at least once every 120 months,~~ by verifying that the valve checks flow.*

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

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying the continuity of the explosive charge.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by removing the explosive squib from the explosive valve, ~~such that each explosive squib in each explosive valve will be tested at least once per 120 months,~~ and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and/or operating life, as applicable.

*The reactor vessel head seal leak detection line (penetration 29A) excess flow check valve is not required to be tested pursuant to this requirement.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

b. Demonstrated OPERABLE:

1. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program and within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel.

2. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying both position indicators OPERABLE by observing expected valve movement during the cycling test.

3. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

a) Verifying each valve's opening setpoint, from the closed position, to be 0.5 psid ± 5%, and

b) Verifying both position indicators OPERABLE by performance of a CHANNEL CALIBRATION.

c) Verifying that each outboard valve's position indicator is capable of detecting disk displacement ≥0.050", and each inboard valve's position indicator is capable of detecting disk displacement ≥0.120".

3/4.6.5 SECONDARY CONTAINMENT

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Without REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY, restore REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be demon-strated by:

a. Verifying ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program that the pressure within the reactor enclosure secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program that:

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

2. At least one door in each access to the reactor enclosure secondary containment is closed.

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

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

1. Verifying that one standby gas treatment subsystem will draw down the reactor enclosure secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 916 seconds with the reactor enclosure recirc system in operation and

2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the reactor enclosure secondary containment at a flow rate not exceeding 2500 cfm with wind speeds of ≤ 7.0 mph as measured on the wind instrument on Tower 1, elevation 30' or, if that instrument is unavailable, Tower 2, elevation 159'.

3/4.6.5 SECONDARY CONTAINMENT

REFUELING AREA SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

Without REFUELING AREA SECONDARY CONTAINMENT INTEGRITY, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specifica-tion 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program that the pressure within the refueling area secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program that:

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

   2. At least one door in each access to the refueling area secondary containment is closed.

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

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

   Operating one standby gas treatment subsystem for one hour and main-taining greater than or equal to 0.25 inch of vacuum water gauge in the refueling area secondary containment at a flow rate not exceeding 764 cfm.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel, with the vessel head removed and fuel in the vessel.

REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.1 The reactor enclosure secondary containment ventilation system automatic isolation valves shall be OPERABLE:

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more of the reactor secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

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

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

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

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 Each reactor enclosure secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.2 The refueling area secondary containment ventilation system automatic isolation valves shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

With one or more of the refueling area secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

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

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

Otherwise, in OPERATIONAL CONDITION*, suspend handling of irradiated fuel in the refueling area secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.2.2 Each refueling area secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during opera-tions with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

STANDBY GAS TREATMENT SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

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

ACTION:

a. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or:

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

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

b. With both standby gas treatment subsystems inoperable in OPERATIONAL CONDITION *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS or operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

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*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

SURVEILLANCE REQUIREMENTS (Continued)

b. ~~At least once per 24* months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 5764 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

3. Verify that when the fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III) when tested in accordance with ANSI N510-1980.

4. Verify that the pressure drop across the refueling area to SGTS prefilter is less than 0.25 inches water gage while operating at a flow rate of 2400 cfm ± 10%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 9.1 inches water gauge while operating the filter train at a flow rate of 8400 cfm ± 10%.

~~*Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52, Revision 2, March 1978.~~

REACTOR ENCLOSURE RECIRCULATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.4 Two independent reactor enclosure recirculation subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one reactor enclosure recirculation subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both reactor enclosure recirculation subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hors.

SURVEILLANCE REQUIREMENTS

4.6.5.4 Each reactor enclosure recirculation subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates properly.

b. ~~At least once per 24* months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 60,000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ATM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

3. Verifying a subsystem flow rate of 60,000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980.

~~*Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52, Revision 2, March 1978.~~

SURVEILLANCE REQUIREMENTS (Continued)

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows, the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the filter train at a flow rate of 60,000 cfm ± 10%, verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

2. Verifying that the filter train starts and the isolation valves which take suction on and return to the reactor enclosure open on each of the following test signals:

a. Manual initiation from the control room, and

b. Simulated automatic initiation signal.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 60,000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 60,000 cfm ± 10%.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

PRIMARY CONTAINMENT HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.6.1 Two independent primary containment hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one primary containment hydrogen recombiner system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.1 Each primary containment hydrogen recombiner system shall be demonstrated OPERABLE:

a. ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program by performance of:

   1. A CHANNEL CHECK of all Control Room Recombiner Instrumentation.

   2. A Trickle Heat Circuit check.

   3. A Heater Coil Check.

   4. A verification of valve operation by stroking all the valves to their proper positions.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

   1. Performing a CHANNEL CALIBRATION of all control room recombiner instrumentation and control circuits.

   2. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test within 30 minutes following the below required functional test. The resistance to ground for any heater phase shall be greater than or equal to one (1) megohm.

   3. Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure; i.e., loose wiring or structural connections, deposits of foreign materials, etc.

   4. Verifying during a recombiner system functional test that the minimum heater outlet gas temperature increases to greater than or equal to 1150°F within 120 minutes and maintained for at least one hour.

c. By measuring the system leakage rate:

   1. As a part of the overall integrated leakage rate test required by Specification 3.6.1.2, or

   2. By measuring the leakage rate of the system outside of the contain-ment isolation valves at P_a, 44.0 psig, on the schedule required by Specification 4.6.1.2, and including the measured leakage as a part of the leakage determined in accordance with Specification 4.6.1.2.

DRYWELL HYDROGEN MIXING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.2 Four independent drywell unit cooler hydrogen mixing subsystems (1AV212, 1BV212, 1GV212, 1HV212) shall be OPERABLE with each subsystem consist-ing of one unit cooler fan.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell unit cooler hydrogen mixing subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 Each drywell unit cooler hydrogen mixing subsystem shall be demonstrated OPERABLE ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program by:

a. Starting the system from the control room, and

b. Verifying that the system operates for at least 15 minutes.

DRYWELL AND SUPPRESSION CHAMBER OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

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

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

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

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.6.3 The drywell and suppression chamber oxygen concentration shall be verified to be within the limit within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER and ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program thereafter.

*See Special Test Exception 3.10.5.
**Specification 3.6.1.8 is applicable during this 24 hour period.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

5. With two RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 30 days, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With three RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

7. With four RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 8 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required residual heat removal service water system subsystem(s) shall be demonstrated OPERABLE:

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

*A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

ACTION: (Continued)

4. With three ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 72 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With four ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 8 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5:

1. With only one emergency service water pump and its associated flowpath OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated safety related equipment inoperable and take the ACTION required by Specifications 3.5.2 and 3.8.1.2.

c. In OPERATIONAL CONDITION *

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or verify adequate cooling remains available for the diesel generators required to be OPERABLE or declare the associated diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENT

4.7.1.2 At least the above required emergency service water system loop(s) shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each automatic valve actuates to its correct position on its appropriate ESW pump start signal.

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

*When handling irradiated fuel in the secondary containment.
**An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, then the ESW pump/diesel generator pair is inoperable.

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The spray pond shall be OPERABLE with:

a. A minimum pond water level at or above elevation 250' 10" Mean Sea Level, and

b. A pond water temperature of less than or equal to 88°F.

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

ACTION:

With the requirements of the above specification not satisfied:

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

b. In OPERATIONAL CONDITION 4 or 5, declare the RHRSW system and the emergency service water system inoperable and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2.

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

SURVEILLANCE REQUIREMENTS

4.7.1.3 The spray pond shall be determined OPERABLE:

a. By verifying the pond water level to be greater than its limit ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

b. By verifying the water surface temperature (within the upper two feet of the surface) to be less than or equal to 88°F in accordance with the Surveillance Frequency Control Program.

~~1. at least once per 4 hours when the spray pond temperature is greater than or equal to 80°F; and~~

~~2. at least once per 2 hours when the spray pond temperature is greater than or equal to 85°F; and~~

~~3. at least once per 24 hours when the spray pond temperature is greater than 32°F.~~

c. By verifying all piping above the frost line is drained:

1. within one (1) hour after being used when ambient air temperature is below 40°F; or

2. when ambient air temperature falls below 40°F if the piping has not been previously drained.

*When handling irradiated fuel in the secondary containment.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency fresh air supply system subsystems shall be OPERABLE.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3 with one control room emergency fresh air supply subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4, 5, or *:

1. With one control room emergency fresh air supply subsystems inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or initiate and maintain operation of the OPERABLE subsystem in the radiation isolation mode of operation.

2. With both control room emergency fresh air supply subsystems inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION*.

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency fresh air supply subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 12 hours~~ In accordance with the Surveillance Frequency Control Program by verifying the control room air temperature to be less than or equal to 85°F effective temperature.

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

c. ~~At least once per 24** months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 3000 cfm ± 10%.

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* When irradiated fuel is being handled in the secondary containment.

~~** Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52, Revision 2, March 1978.~~

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

3. Verifying a subsystem flow rate of 3000 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

e. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the subsystem at a flow rate of 3000 cfm ± 10%; verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

2. Verifying that on each of the below chlorine isolation mode actuation test signals, the subsystem automatically switches to the chlorine isolation mode of operation and the isolation valves close within 5 seconds:

   a) Outside air intake high chlorine, and

   b) Manual initiation from the control room.

3. Verifying that on each of the below radiation isolation mode actuation test signals, the subsystem automatically switches to the radiation isolation mode of operation and the control room is maintained at a positive pressure of at least 1/8 inch water gauge relative to the turbine enclosure and auxiliary equipment room and outside atmosphere during subsystem operation with an outdoor air flow rate less than or equal to 525 cfm:

   a) Outside air intake high radiation, and

   b) Manual initiation from control room.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

b. In the event the RCIC system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

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

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

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

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

b. ~~At least once per 92 days~~ In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

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

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

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

4. Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

3/4.7.5 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

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

   1. Decontaminate and repair the sealed source, or

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

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

a. The licensee, or

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

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

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

a. Sources in use - ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program for all sealed sources containing radioactive material:

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

   2. In any form other than gas.

3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE as determined by the number of operable main turbine bypass valves being greater than or equal to that specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or take the ACTION required by Specification 3.2.3.c.

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE ~~at least once per~~ in accordance with the Surveillance Frequency Control Program:

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

b. ~~24 months~~ By performing a system functional test which includes simulated automatic actuation, and by verifying that each automatic valve actuates to its correct position, and

c. ~~24 months~~ By determining TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to the value specified in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

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

a. Determined OPERABLE ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

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

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

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

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

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

4. Verify that the diesel can start* and gradually accelerate to synchronous speed with generator voltage and frequency at 4280 ± 120 volts and 60 ± 1.2 HZ.

5. Verify diesel is synchronized, gradually loaded* to an indicated 2700-2800 KW** and operates with this load for at least 60 minutes.

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

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 225 psig.

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*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine pre-lube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

SURVEILLANCE REQUIREMENTS (Continued)

b. By removing accumulated water:

1) From the day tank ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program and after each occasion when the diesel is operated for greater than 1 hour, and

2) From the storage tank ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program.

c. By sampling new fuel oil in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1) By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

a) An API Gravity of within 0.3 degrees at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

c) A flash point equal to or greater than 125°F, and

d) A clear and bright appearance with proper color when tested in accordance with ASTM D4176-82.

2) By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

d. ~~At least once every 31 days~~ In accordance with the Surveillance Frequency Control Program by obtaining a sample of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A, except that the filters specified in ASTM D2276-78, Sections 5.1.6 and 5.1.7, may have a nominal pore size of up to three (3) microns.

e. ~~At the following frequency~~ In accordance with the Surveillance Frequency Control Program by:

1. Deleted

2. ~~Every 24 months~~ Verifying each diesel generator's capability to reject a load of greater than or equal to that of its single largest post-accident load while maintaining voltage at 4285 ± 420 volts and frequency at 60 ± 1.2 hz and after steady state conditions are reached, voltage is maintained at 4280 ± 120 volts.

SURVEILLANCE REQUIREMENTS (Continued)

3. ~~Every 24 months~~ Verifying the diesel generator capability to reject a load of 2850 kW without tripping. The generator voltage shall not exceed 4784 volts during and following the load rejection.

4. ~~Every 24 months~~ Simulating a loss-of-offsite power by itself, and:

   a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency busses within 10 seconds, energizes the auto-connected loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

5. ~~Every 24 months~~ Verifying that on an ECCS actuation test signal, without loss-of-offsite power, the diesel generator starts* on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. ~~Every 24 months~~ Simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, and:

   a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency busses within 10 seconds, energizes the auto-connected shutdown loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

7. ~~Every 24 months~~ Verifying that all automatic diesel generator trips, except engine overspeed and generator differential over-current are automatically bypassed upon an ECCS actuation signal.

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* This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warm-up procedures, and as applicable regarding loading and shutdown recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

8. a) ~~Every 24 months~~ Verifying the diesel generator operates* for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to an indicated 2950-3050 kW** and during the remaining 22 hours of this test, the diesel generator shall be loaded to an indicated 2700-2800 kW**.

   b) ~~Every 24 months~~ Verifying that, within 5 minutes of shutting down the diesel generator after the diesel generator has operated* for at least 2 hours at an indicated 2700-2800 kW**, the diesel generator starts*. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal.

9. ~~Every 24 months~~ Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 3100 kW.

10. ~~Every 24 months~~ Verifying the diesel generator's capability to:

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

    b) Transfer its loads to the offsite power source, and

    c) Be restored to its standby status.

11. ~~Every 24 months~~ Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

12. ~~Every 24 months~~ Verifying that the automatic load sequence timers are OPERABLE with the interval between each load block within ± 10% of its design interval.

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* This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

** This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

SURVEILLANCE REQUIREMENTS (Continued)

13. ~~Every 24 months~~ Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

    a) Control Room Switch In Pull-To-Lock (With Local/Remote Switch in Remote)

    b) Local/Remote Switch in Local

    c) Emergency Stop

f. ~~At least once per 10 years~~ In accordance with the Surveillance Frequency Control Program or after any modifications which could affect diesel generator interdependence by starting* all four diesel generators simultaneously, during shutdown, and verifying that all four diesel generators accelerate to at least 882 rpm in less than or equal to 10 seconds.

g. ~~At least once per 10 years~~ In accordance with the Surveillance Frequency Control Program by:

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

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

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

h. ~~At least once per 184 days~~ In accordance with the Surveillance Frequency Control Program the diesel generator shall be started* and verified to accelerate to synchronous speed in less than or equal to 10 seconds. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual***

b) Simulated loss-of-offsite power by itself.

c) Simulated loss-of-offsite power in conjunction with an ECCS actuation test signal.

d) An ECCS actuation test signal by itself.

The generator shall be manually synchronized to its appropriate emergency bus, loaded to an indicated 2700-2800 KW** in less than or equal to 200 seconds, and operate for at least 60 minutes. This test, if it is performed so it coincides with the testing required by Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5, may also serve to concurrently meet those requirements as well.

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2 within 30 days. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

***If diesel generator started manually from the control room, 10 seconds after the automatic prelube period.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

NUMBER OF FAILURES IN LAST 20 VALID DEMANDS*	TEST FREQUENCY
less than or equal to 1 or,	~~at least once per 31 days~~ In accordance with the Surveillance Frequency Control Program
greater than or equal to 2**	~~at least once per 7 days~~ In accordance with the Surveillance Frequency Control Program

*Criteria for determining the number of failures and number of valid demands shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, but determined on a per diesel generator basis.

**The associated test frequency shall be maintained until seven consecutive failure free demands have been performed and the number of failures in the last 20 demands have been reduced to one.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each Division 1 and 2 battery float current is ≤ 2 amps, and Division 3 and 4 battery float current is ≤ 1 amp when battery terminal voltage is greater than or equal to the minimum established float voltage of 4.8.2.1.a.2, and

2. Total battery terminal voltage for each 125-volt battery is greater than or equal to the minimum established float voltage.

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each battery pilot cell voltage is ≥ 2.07 volts,

2. Each battery connected cell electrolyte level is greater than or equal to minimum established design limits, and

3. The electrolyte temperature of each pilot cell is greater than or equal to minimum established design limits.

c. ~~At least once per 92 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each battery connected cell voltage is ≥ 2.07 volts.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. The battery chargers will supply the currents listed below at greater than or equal to the minimum established float voltage for at least 4 hours.

Charger	Current (Amperes)
1BCA1	300
1BCA2	300
1BCB1	300
1BCB2	300
1BCC	75
1BCD	75

2. The battery capacity is adequate to supply and maintain in OPERABLE status the required emergency loads for the design duty cycle when subjected to a battery service test.

SURVEILLANCE REQUIREMENTS (Continued)

e. ~~At least once per 60 months~~ In accordance with the Surveillance Frequency Control Program by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test or modified performance discharge test. The modified performance discharge test may be performed in lieu of the battery service test (Specification 4.8.2.1.d.2).

f. Performance discharge tests or modified performance discharge tests of battery capacity shall be given as follows:

1. ~~At least once per 12 months~~ In accordance with the Surveillance Frequency Control Program when:
   (a) The battery shows degradation or
   (b) The battery has reached 85% of expected life with battery capacity < 100% of manufacturer's rating, and

2. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program when battery has reached 85% of expected life with battery capacity ≥ 100% of manufacturer's rating.

~~Corrected by letter dated June 19, 1995~~

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one of the above required Unit 1 A.C. distribution system divisions not energized, reenergize the division within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 1 D.C. distribution system divisions not energized, reenergize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any of the above required Unit 2 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system divisions shall be determined energized ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With less than two divisions of the above required Unit 1 A.C. distribution systems energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

b. With less than two divisions of the above required Unit 1 D.C. distribution systems energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. With any of the above required Unit 2 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system divisions shall be determined energized ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

*When handling irradiated fuel in the secondary containment.

MOTOR-OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of all Class 1E motor operated valves shall be either:

a. Continously bypassed for all valves with maintained position control switches; or,

b. Bypassed only under accident conditions for all valves with spring-return-to-normal control switches.

APPLICABILITY: Whenever the motor-operated valve is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required valves not bypassed continuously or only under accident conditions, as applicable, restore the thermal overload bypass within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection for the above required valves which are continuously bypassed and temporarily placed in force only when the valve motor is undergoing periodic or maintenance testing shall be verified to be bypassed following periodic or maintenance testing during which the thermal overload protection was temporarily placed in force.

4.8.4.2.2 ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program, a CHANNEL FUNCTIONAL TEST of all those valves which are bypassed only under accident conditions (valves with spring- return-to-normal control switches) shall be performed to verify that the thermal overload protection will be bypassed under accident conditions.

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.3 Two reactor protection system (RPS) electric power monitoring channels for each inservice RPS Inverter or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

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

b. With both RPS electric power monitoring channels for an inservice RPS Inverter or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 24 hours or remove the associated RPS Inverter or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

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

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by demonstrating the OPERABILITY of overvoltage, undervoltage, and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic, and output circuit breakers and verifying the following Allowable Values.

1. Overvoltage ≤ 127.6 VAC,

2. Undervoltage ≥ 110.7 VAC,

3. Underfrequency ≥ 57.05 Hz.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks* shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during control rod withdrawal or CORE ALTERATIONS, as applicable.

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks* that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

*The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least two source range monitor (SRM) channels* shall be OPERABLE and inserted to the normal operating level with:

a. Continuous visual indication in the control room,

b. At least one with audible alarm in the control room,

c. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

d. Unless adequate shutdown margin has been demonstrated, the shorting links shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn.**

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. ~~At least once per 12 hours~~ In accordance with the Surveillance Frequency Control Program:

1. Performance of a CHANNEL CHECK,

2. Verifying the detectors are inserted to the normal operating level, and

3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

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*These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core. The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

c. Verifying that the channel count rate is at least 3.0 cps:*

1. Prior to control rod withdrawal,

2. Prior to ~~and at least once per 12 hours during~~ CORE ALTERATIONS, and

3. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program.

d. Verifying, within 8 hours prior to and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program ~~during~~, that the RPS circuitry "shorting links" have been removed during:

1. The time any control rod is withdrawn**, unless adequate shutdown margin has been demonstrated, or

2. Shutdown margin demonstrations.

*May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1. These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS, except that one control rod may be withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified, ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

*Except control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**See Special Test Exception 3.10.3.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communication shall be maintained between the control room and refueling floor personnel.

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.*

ACTION:

When direct communication between the control room and refueling floor personnel cannot be maintained, immediately suspend CORE ALTERATIONS.*

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communication between the control room and refueling floor personnel shall be demonstrated ~~at least once per 12 hours~~ during CORE ALTERATIONS in accordance with the Surveillance Frequency Control Program.*

*Except movement of control rods with their normal drive system.

3/4.9.7 CRANE TRAVEL-SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 1200 pounds shall be prohibited from travel over fuel assemblies in the spent fuel storage pool racks.

APPLICABILITY: With fuel assemblies in the spent fuel storage pool racks.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 Crane interlocks which prevent crane travel over fuel assemblies in the spent fuel storage pool racks shall be demonstrated OPERABLE within 7 days prior to and ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during crane operation.

3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least 22 feet of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program during handling of fuel assemblies or control rods within the reactor pressure vessel.

3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.9 At least 22 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage pool area after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the spent fuel storage pool shall be determined to be at least at its minimum required depth ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program thereafter until a control rod and associated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

SURVEILLANCE REQUIREMENTS

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 One (1) RHR shutdown cooling subsystem shall be OPERABLE and in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With the required RHR shutdown cooling subsystem inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available.

b. With the required action and associated completion time of Action "a" above not met.

   1. Immediately suspend loading of irradiated fuel assemblies into the reactor pressure vessel; and

   2. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   3. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   4. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* The required RHR shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and one (1) RHR shutdown cooling subsystem shall be in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With one (1) or two (2) required RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable required RHR shutdown cooling subsystem.

b. With the required action and associated completion time of Action "a" above not met:

   1. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   2. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   3. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* The required operating shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3, and 3.9.1 and Table 1.2 may be suspended to permit the reactor pressure vessel closure head and the drywell head to be removed and the primary containment air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during low power PHYSICS TESTS.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3, and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

a. The source range monitors are OPERABLE with the RPS circuitry "shorting links" removed per Specification 3.9.2.

b. The rod worth minimizer is OPERABLE per Specification 3.1.4.1 and is programmed for the shutdown margin demonstration, or conformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The "continuous rod withdrawal" control shall not be used during out-of-sequence movement of the control rods.

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

4.10.3 Within 30 minutes prior to and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program during the performance of a shutdown margin demonstration, verify that;

a. The source range monitors are OPERABLE per Specification 3.9.2,

b. The rod worth minimizer is OPERABLE with the required program per Specification 3.1.4.1 or a second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown margin demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

3/4.10.4 RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER, or

b. The Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS and the Startup Test Program.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS and the Startup Test Program.

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS.

3/4.10.5 OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.10.5 The provisions of Specification 3.6.6.3 may be suspended during the performance of the Startup Test Program until either the required 100% of RATED THERMAL POWER trip tests have been completed or the reactor has operated for 120 Effective Full Power Days.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

With the requirements of the above specification not satisfied, be in at least STARTUP within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.5 The Effective Full Power Days of operation shall be verified to be less than 120, by calculation, ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during the Startup Test Program.

3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during training startups.

LIQUID HOLDUP TANKS

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in any outside temporary tanks shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit and describe the events leading to this condition in the next Annual Radioactive Effluent Release Report.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each of the above tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program when radioactive materials are being added to the tank.

MAIN CONDENSER

LIMITING CONDITION FOR OPERATION

3.11.2.6 The rate of the sum of the activities of the noble gases Kr-85m, Kr-87, Kr-88, Xe-133, Xe-135, and Xe-138 measured at the recombiner after-condenser discharge shall be limited to less than or equal to 330 millicuries/second.

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

ACTION:

With the rate of the sum of the activities of the specified noble gases at the recombiner after-condenser discharge exceeding 330 millicuries/second, restore the gross radioactivity rate to within its limit within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.11.2.6.1 The rate of the sum of the activities of noble gases at the recombiner after-condenser discharge shall be continously monitored in accordance with Specification 3.3.7.12.

4.11.2.6.2 The rate of the sum of the activities of the specified noble gases from the recombiner after-condenser discharge shall be determined to be within the limits of Specification 3.11.2.6 at the following frequencies by performing an isotopic analysis of a representative sample of gases taken at the recombiner after condenser discharge:

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

b. Within 4 hours following an increase, as indicated by the Main Condenser Off-Gas Pretreatment Radioactivity Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level or air in-leakage, in the nominal steady-state fission gas release from the primary coolant.

c. The provisions of Specification 4.0.4 are not applicable.

*When the main condenser air ejector is in operation.

CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances ~~intervals~~ are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 topical report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume ~~once each 24 hours~~ assures that the solution is available for use.

Replacement of the explosive charges in the valves ~~at regular intervals~~ will assure that these valves will not fail because of deterioration of the charges.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores." Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM chanels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. ~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMARC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

Actions a, b and c define the action(s) required when RPS channels are discovered to be inoperable. For those actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDo-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated may 15, 1991).

The measurement of response time at the ~~specified~~ frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions (Table 3.3.1-2, Items 2.b and 2.c). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The ~~specified~~ surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor has been determined in accordance with the Surveillance Frequency Control Program ~~GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).~~

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Drywell and containment hydrogen and oxygen analyzers are Category I instruments provided to detect high hydrogen or oxygen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions.

When two hydrogen monitor channels are inoperable, one hydrogen monitor channel must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit; the length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit; and the availability of the hydrogen recombiners, the Containment Purge System, and the Post Accident Sampling Systems.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 CHLORINE AND TOXIC GAS DETECTION SYSTEMS

The OPERABILITY of the chlorine and toxic gas detection systems ensures that an accidental chlorine and/or toxic gas release will be detected promptly and the necessary protective actions will be automatically initiated for chlo-rine and manually initiated for toxic gas to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the chlorine isolation mode of operation to provide the required protection. Upon detection of a high concentration of toxic gas, the control room emergency ventilation system will manually be placed in the chlorine isolation mode of operation to provide the required protection. The detection systems required by this speci-fication are consistent with the recommendations of Regulatory Guide 1.95, "Pro-tection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release," February 1975.

There are three toxic gas detection subsystems. The high toxic chemical concentration alarm in the Main Control Room annunciates when two of the three subsystems detect a high toxic gas concentration. An Operate/Inop keylock switch is provided for each subsystem which allows an individual subsystem to be placed in the tripped condition. Placing the keylock switch in the INOP position initiates one of the two inputs required to initiate the alarm in the Main Control Room.

~~Specified~~ ~~s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

RECIRCULATION SYSTEM (Continued)

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduced since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron flux noise level obtained at a specific core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline data taken at lower rod lines (i.e. lower power) will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations ~~in~~ at the ~~specified~~ frequency specified in the Surveillance Frequency Control Program.

ACTIONS (Continued)

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment of more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While in the primary containment atmosphere gases radioactivity monitor is INOPERABLE, Primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. If any required ACTION of Conditions A, B, C, D or E cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a

This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. ~~The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off-normal conditions.~~

SURVEILLANCE REQUIREMENTS (Continued)

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. ~~The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.~~

SR 4.4.3.1.c
The SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. ~~The Frequency of 24 months is for a typical refueling cycle and considers channel reliability. Operating experience has proven this frequency to be acceptable.~~

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage. Operating experience has proven this frequency to be acceptable.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3.
4. LGS UFSAR, Section 5.2.5.2.1.5.
5. LGS UFSAR, Section 5.2.5.2.1.4.
6. LGS UFSAR, Section 5.2.5.2.1.1(2).
7. GEAP-5620, April 1968
8. NUREG-75/067, October 1975.
9. LGS UFSAR, Section 5.2.5.6.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

ECCS - OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS sub-system out-of-service time allowances.

Verification ~~every 31 days~~ that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply. ~~The 31 day Frequency takes into consideration administrative controls over operation of the gas system and alarms for low gas pressure.~~

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to £ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. ~~The 31 day Frequency is consistent with other PCIV requirements.~~

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested ~~at least once every 10 years~~ in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. ~~The 10 year test interval is based on other performance-based testing programs.~~ Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system ~~once per 24 months~~ in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA or refueling accident (SGTS only). The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA and refueling accident analyses. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

"Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE Standard 450-1995. ~~The 7-day Frequency is consistent with IEEE Standard 450-1995.~~

This Surveillance Requirement (4.8.2.1.a.1) states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained, the Actions of 3.8.2.1 Action a., provides the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). ~~The 7-day Frequency is consistent with manufacturer recommendations and IEEE Standard 450-1995.~~

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V. ~~The Frequency for cell voltage verification every 31 days for pilot cell, and 92 days for each connected cell, is consistent with IEEE Standard 450-1995.~~

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. ~~The Frequency is consistent with IEEE Standard 450-1995.~~

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. ~~The Frequency is consistent with IEEE Standard 450-1995.~~

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

PROCEDURES AND PROGRAMS (Continued)

i. Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries For Stationary Applications," of the following:

a. Actions to restore battery cells with float voltage < 2.13 volts, and

b. Actions to equalize and test battery cells that have been discovered with electrolyte level below the minimum established design limit.

j. Surveillance Frequency Control Program

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

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

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

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

ATTACHMENT 3

LICENSE AMENDMENT REQUEST

LIMERICK GENERATING STATION, UNITS 1 AND 2
DOCKET NOS. 50-352 AND 50-353

RELOCATION OF SURVEILLANCE TEST INTERVALS FROM THE TECHNICAL SPECIFICATIONS TO A LICENSEE-CONTROLLED PROGRAM

UNIT 2 MARKED-UP TECHNICAL SPECIFICATIONS AND BASES PAGES FOR THE PROPOSED CHANGE

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3/4.4 REACTOR COOLANT SYSTEM

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

2. If the inoperable control rod(s) is inserted, within 1 hour disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

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

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

d. With one or more scram discharge volume (SDV) vent or drain lines with one valve inoperable, restore the inoperable valve(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

e. With one or more SDV vent or drain lines with both valves inoperable, isolate the associated line within 8 hours **** or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ Verifying each valve to be open,* and

b. ~~At least once per 92 days~~ Cycling each valve through at least one complete cycle of full travel.

---

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

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

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

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

SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.2 When above the preset power level of the RWM, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program, and

b. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6, and 4.1.3.7.

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

a. The scram discharge volume drain and vent valves OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves:

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

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume scram and control rod block level instrumentation ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 5, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the maximum scram insertion time of one or more control rods exceeding 7 seconds:

a. Declare the control rod(s) with the slow insertion time inoperable, and

b. Perform the Surveillance Requirements of Specification 4.1.3.2c. at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

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

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement and, during single control rod scram time tests, the control rod drive pumps shall be isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER with reactor coolant pressure greater than or equal to 950 psig, following CORE ALTERATIONS or after a reactor shutdown that is greater than 120 days.

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods in accordance with either "1" or "2" as follows:

   1.a Specifically affected individual control rods shall be scram time tested at zero reactor coolant pressure and the scram insertion time from the fully withdrawn position to notch position 05 shall not exceed 2.0 seconds, and

   1.b Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure prior to exceeding 40% of RATED THERMAL POWER.

   2. Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure.

c. For at least 10% of the control rods, with reactor coolant pressure greater than or equal to 950 psig, on a rotating basis, and ~~at least once per 120 days of POWER OPERATION~~ in accordance with the Surveillance Frequency Control Program.

2. With more than one withdrawn control rod with the associated scram accumulator inoperable or no control rod drive pump oper-ating, immediately place the reactor mode switch in the Shutdown position.

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program by verifying that the indicated pressure is greater than or equal to 955 psig unless the control rod is inserted and disarmed or scrammed.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program that the position of each control rod is indicated,

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

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

ROD BLOCK MONITOR

LIMITING CONDITION FOR OPERATION

3.1.4.3 Both rod block monitor (RBM) channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER and less than 90% of RATED THERMAL POWER with MCPR less than 1.70, or THERMAL POWER greater than or equal to 90% of rated with MCPR less than 1.40.

ACTION:

a. With one RBM channel inoperable:

   1. Verify that the reactor is not operating on a LIMITING CONTROL ROD PATTERN, and

   2. Restore the inoperable RBM channel to OPERABLE status within 24 hours.

   Otherwise, place the inoperable rod block monitor channel in the tripped condition within the next hour.

b. With both RBM channels inoperable, place at least one inoperable rod block monitor channel in the tripped condition within 1 hour.

SURVEILLANCE REQUIREMENTS

4.1.4.3 Each of the above required RBM channels shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION ~~at the frequencies and~~ for the OPERATIONAL CONDITIONS specified in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

b. CHANNEL FUNCTIONAL TEST prior to control rod withdrawal when the reactor is operating on a LIMITING CONTROL ROD PATTERN.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system, consisting of a minimum of two pumps and corresponding flow paths, shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With only one pump and corresponding explosive valve OPERABLE, restore one inoperable pump and corresponding explosive valve to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

2. With standby liquid control system otherwise inoperable, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

2. The available volume of sodium pentaborate solution is at least 3160 gallons.

3. The temperature of the pump suction piping is within the limits of Figure 3.1.5-1 for the most recent concentration analysis.

SURVEILLANCE REQUIREMENTS (Continued)

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying the continuity of the explosive charge.

2. Determining by chemical analysis and calculation* that the available weight of sodium pentaborate is greater than or equal to 3754 lbs; the concentration of sodium pentaborate in solution is less than or equal to 13.8% and within the limits of Figure 3.1.5-1 and; the following equation is satisfied:

$$\frac{C}{13\%\ \text{wt.}} \times \frac{E}{29\ \text{atom}\ \%} \times \frac{Q}{86\ \text{gpm}} \geq 1$$

where

C = Sodium pentaborate solution (% by weight)
Q = Two pump flowrate, as determined per surveillance requirement 4.1.5.c.
E = Boron 10 enrichment (atom % Boron 10)

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

c. Demonstrating that, when tested pursuant to Specification 4.0.5, the minimum flow requirement of 41.2 gpm per pump at a pressure of greater than or equal to 1230±25 psig is met.

d. ~~At least once per 24 months during shutdown~~ In accordance with the Surveillance Frequency Control Program by:

1. Initiating at least one of the standby liquid control system loops, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of the batch successfully fired. All injection loops shall be tested in 3 operating cycles.

2. Verify all heat-treated piping between storage tank and pump suction is unblocked.**

e. Prior to addition of Boron to storage tank verify sodium pentaborate enrichment to be added is ≥ 29 atom % Boron 10.

---

* This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after water or boron addition or solution temperature is restored.

** This test shall also be performed whenever suction piping temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after solution temperature is restored.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of axial location and AVERAGE PLANAR EXPOSURE shall be within limits based on applicable APLHGR limit values which have been determined by approved methodology for the respective fuel and lattice types. When hand calculations are required, the APLHGR for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limiting value for the most limiting lattice (excluding natural uranium) as shown in the CORE OPERATING LIMITS REPORT (COLR). During operation, the APLHGR for each fuel type shall not exceed the above values multiplied by the appropriate reduction factors for power and flow as defined in the COLR.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limiting value, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limiting value:

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) EOC-RPT inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

c. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) main turbine bypass valve inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2a and during reactor startups prior to control rod scram time tests in accordance with Specification 4.1.3.2.b.1.b, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit including application of the MCPR(P) and MCPR(F) factors as determined from the CORE OPERATING LIMITS REPORT.

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGRs shall be determined to be equal to or less than the limit:

a. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, and 2.e. Functions 2.a, 2.b, 2.c, and 2.d do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific reactor trip system.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (m)	CHANNEL FUNCTIONAL TEST (m)	CHANNEL CALIBRATION(a)(m)	CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	~~S~~(b)	~~W~~	~~R~~	2
	~~S~~	~~W~~(j)	~~R~~	3(i), 4(i), 5(i)
b. Inoperative	N.A.	~~W~~(j)	N.A.	2, 3(i), 4(i), 5(i)
2. Average Power Range Monitor(f):				
a. Neutron Flux - Upscale (Setdown)	~~D~~(b)	~~SA~~(l)	~~R~~	2
b. Simulated Thermal Power - Upscale	~~D~~	~~SA~~(e)	~~W~~(d), ~~R~~(g)	1
c. Neutron Flux - Upscale	~~D~~	~~SA~~	~~W~~(d), ~~R~~	1
d. Inoperative	N.A.	~~SA~~	N.A.	1, 2
e. 2-Out-Of-4 Voter	~~D~~	~~SA~~	N.A.	1, 2
3. Reactor Vessel Steam Dome Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2(h)
4. Reactor Vessel Water Level-Low, Level 3	~~S~~	~~Q~~	~~R~~	1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.	~~Q~~	~~R~~	1
6. DELETED	~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~
7. Drywell Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	~~S~~	~~Q~~	~~R~~	1, 2, 5(i)
b. Float Switch	N.A.	~~Q~~	~~R~~	1, 2, 5(i)

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (m)	CHANNEL FUNCTIONAL TEST (m)	CHANNEL CALIBRATION(a)(m)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Turbine Stop Valve - Closure	N.A.	~~Q~~	~~R~~	1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.	~~Q~~	~~R~~	1
11. Reactor Mode Switch Shutdown Position	N.A.	~~R~~	N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.	~~W~~	N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for a least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.
(c) DELETED
(d) ~~This~~ The more frequent calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.
(e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.
(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH).
(g) The less frequent c~~C~~alibration includes the flow input function.
(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.
(k) DELETED
(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.
(m) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operations of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.

** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
2) Low, Low, Low - Level 1	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. DELETED	~~DELETED~~	~~DELETED~~	~~DELETED~~	DELETED
c. Main Steam Line Pressure - Low	~~S~~	~~Q~~	~~R~~	1
d. Main Steam Line Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. Condenser Vacuum - Low	~~S~~	~~Q~~	~~R~~	1, 2**, 3**
f. Outboard MSIV Room Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
h. Manual Initiation	N.A.	~~R~~	N.A.	1. 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level## Low - Level 3	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. RWCS Area Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. SLCS Initiation	N.A.	~~R~~	N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
b. HPCI Steam Supply Pressure, Low	~~S~~	~~Q~~	~~R~~	1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
d. HPCI Equipment Room Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
e. HPCI Equipment Room Δ Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
f. HPCI Pipe Routing Area Temperature - High	~~S~~	~~Q~~	~~R~~	1, 2, 3
g. Manual Initiation	N.A.	~~R~~	N.A.	1, 2, 3
h. HPCI Steam Line Δ Pressure Timer	N.A.	~~Q~~	~~R~~	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	S	Q	R	1, 2, 3
b. RCIC Steam Supply Pressure - Low	S	Q	R	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	S	Q	R	1, 2, 3
d. RCIC Equipment Room Temperature - High	S	Q	R	1, 2, 3
e. RCIC Equipment Room Δ Temperature - High	S	Q	R	1, 2, 3
f. RCIC Pipe Routing Area Temperature - High	S	Q	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. RCIC Steam Line Δ Pressure Timer	N.A.	Q	R	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2	S	Q	R	1, 2, 3
2) Low, Low, Low - Level 1	S	Q	R	1, 2, 3
b. Drywell Pressure ## - High	S	Q	R	1, 2, 3
c. North Stack Effluent Radiation - High	S	Q	R	1, 2, 3
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	S	Q	R	1, 2, 3
f. Deleted				
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low	S	Q	R	1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.	M	Q	1, 2, 3
j. Manual Initiation	N.A.	R	N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level## Low, Low - Level 2	S	Q	R	1, 2, 3
b. Drywell Pressure## - High	S	Q	R	1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	S	Q	R	1, 2, 3
e. Deleted				
f. Deleted				
g. Reactor Enclosure Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. Refueling Area Manual Initiation	N.A.	R	N.A.	*

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

*Required when (1) handling irradiated fuel in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

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

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

c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days, provided that the HPCI and RCIC systems are OPERABLE.

   2. 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.3.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times ~~24 months~~ the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION (a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	Q	R	1, 2, 3, 4*, 5*
d. Manual Initiation	N.A.	R	N.A.	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	Q	R	1, 2, 3
d. Injection Valve Differential Pressure - Low (Permissive)	S	Q	R	1, 2, 3, 4*, 5*
e. Manual Initiation	N.A.	R	N.A.	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM***				
a. Reactor Vessel Water Level - Low Low, Level 2	S	Q	R	1, 2, 3
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Condensate Storage Tank Level - Low	S	Q	R	1, 2, 3
d. Suppression Pool Water Level - High	S	Q	E	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	S	Q	R	1, 2, 3
f. Manual Initiation	N.A.	R	N.A.	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

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

* When the system is required to be OPERABLE per Specification 3.5.2.

** Required OPERABLE when ESF equipment is required to be OPERABLE.

*** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Loss of Voltage Relay 127-11X is not field setable.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

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

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 24 hours.

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

   1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within 24 hours, or, if this action will initiate a pump trip, declare the trip system inoperable.

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

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

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.1-1~~ specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.4.1-1~~

~~ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION~~

~~SURVEILLANCE REQUIREMENTS~~

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

INFORMATION ON THIS PAGE HAS BEEN DELETED

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.4.2.1-1~~ specified in the Surveillance Frequency Control Program.

4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested ~~at least once per 48 months~~ in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured ~~at least once per 60 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.4.2.1-1~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS~~

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

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~~* Including trip system logic testing.~~

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each of the required RCIC system actuation instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies ~~shown in Table 4.3.5.1-1~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.5.1-1. CHANNEL CHECK and CHANNEL CALIBRATION are not required for manual initiation.

4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

~~TABLE 4.3.5.1-1~~

~~REACTOR CORE ISOLATION SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

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

INFORMATION ON THIS PAGE HAS BEEN DELETED

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint** less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS ~~and at the frequencies~~ shown in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

---

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition, provided at least one other operable channel in the same trip system is monitoring that parameter.

**The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 4.3.6-1
CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (h)	CHANNEL FUNCTIONAL TEST (h)	CHANNEL CALIBRATION(a) (h)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	~~Q~~(c)	~~R~~	1*
b. Inoperative	N.A.	~~Q~~(c)	N.A.	1*
c. Downscale	N.A.	~~Q~~(c)	~~R~~	1*
2. APRM				
a. Simulated Thermal Power - Upscale	N.A.	~~SA~~	~~R~~	1
b. Inoperative	N.A.	~~SA~~	N.A.	1, 2
c. Neutron Flux - Downscale	N.A.	~~SA~~	~~R~~	1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.	~~SA~~	~~R~~	2
e. Recirculation Flow - Upscale	N.A.	~~SA~~	~~R~~	1
f. LPRM Low Count	N.A.	~~SA~~	~~R~~	1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	~~M(d)~~(e)~~,W(f)~~	N.A.	2, 5
b. Upscale	N.A.	~~M(d)~~(e)~~,W(f)~~	~~R~~	2, 5
c. Inoperative	N.A.	~~M(d)~~(e)~~,W(f)~~	N.A.	2, 5
d. Downscale	N.A.	~~M(d)~~(e)~~,W(f)~~	~~R~~	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.	~~W~~	N.A.	2, 5
b. Upscale	N.A.	~~W~~	~~R~~	2, 5
c. Inoperative	N.A.	~~W~~	N.A.	2, 5
d. Downscale	N.A.	~~W~~	~~R~~	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.	~~Q~~	~~R~~	1, 2, 5**
6. DELETED	DELETED	DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	~~R~~(g)	N.A.	3, 4

Amendment No. ~~7~~, ~~17~~, ~~48~~, ~~63~~, ~~109~~
~~Corrected by letter dated May 28, 2002~~

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

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

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

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

*** Deleted.

(d) Deleted ~~When in OPERATIONAL CONDITION 2.~~

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) Deleted ~~When in OPERATIONAL CONDITION 5.~~

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

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

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

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

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

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK (c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION (c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	S	Q	R	1, 2, 3, 5 and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	S	M	R	(a)
b. Control Room Direct Radiation Monitor	S	M	R	At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor	S	M	R(b)	At All Times

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When irradiated fuel is being handled in the secondary containment.

(a) With fuel in the spent fuel storage pool.

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

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

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

b. With the number of OPERABLE remote shutdown system controls less than required in Table 3.3.7.4-1, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

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

4.3.7.4.2 Each of the above remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

*Control is not required to be transferred to perform the CHANNEL CHECK.

~~TABLE 4.3.7.4-1~~

~~REMOTE SHUTDOWN SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~INSTRUMENT~~	~~CHANNEL CHECK *~~	~~CHANNEL CALIBRATION~~
~~1. Reactor Vessel Pressure~~	~~M~~	~~R~~
~~2. Reactor Vessel Water Level~~	~~M~~	~~R~~
~~3. Safety/Relief Valve Position, 3 valves~~	~~M~~	~~NA~~
~~4. Suppression Chamber Water Level~~	~~M~~	~~R~~
~~5. Suppression Chamber Water Temperature~~	~~M~~	~~R~~
~~6. Drywell Pressure~~	~~M~~	~~R~~
~~7. Drywell Temperature~~	~~M~~	~~R~~
~~8. RHR System Flow~~	~~M~~	~~R~~
~~9. RHR Service Water Pump Discharge Pressure~~	~~M~~	~~R~~
~~10. RHR Heat Exchanger Service Water Outlet Pressure~~	~~M~~	~~R~~
~~11. RCIC System Flow~~	~~M~~	~~R~~
~~12. RCIC Turbine Speed~~	~~M~~	~~R~~
~~13. Emergency Service Water Pump Discharge Pressure~~	~~M~~	~~R~~
~~14. Condensate Storage Tank Level~~	~~M~~	~~R~~
~~15. RHR Heat Exchanger Bypass Valve (HV-C-51-2F048A) Position Indication (0 - 100%)~~	~~M~~	~~R~~
~~16. RCIC Turbine Tripped Indication~~	~~M~~	~~R~~
~~17. RCIC Turbine Bearing Oil Pressure Low Indication~~	~~M~~	~~R~~
~~18. RCIC Bearing Oil Temperature High Indication~~	~~M~~	~~R~~
~~19. RHR Heat Exchanger Discharge Line High Radiation Indication~~	~~M~~	~~R~~

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~~*Control is not required to be transferred to perform this CHANNEL CHECK.~~

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies ~~shown~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.5-1.

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Chamber Water Level	M	R
4. Suppression Chamber Water Temperature	M	R
5. Suppression Chamber Air Temperature	M	R
6. Primary Containment Pressure	M	R
7. Drywell Air Temperature	M	R
8. Drywell Oxygen Concentration Analyzer	M	Q#
9. Drywell Hydrogen Concentration Analyzer	M	Q*
10. Safety/Relief Valve Position Indicators	M	R
11. Primary Containment Post LOCA Radiation Monitors	M	R**
12. North Stack Wide Range Accident Monitor***	M	R
13. Neutron Flux	M	R

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

*Using calibration gas containing:
Seven volume percent hydrogen, balance nitrogen.

**CHANNEL CALIBRATION shall 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.

***High range noble gas monitors.

#Using calibration gas containing:
Seven volume percent oxygen, balance nitrogen.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

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

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

APPLICABILITY: OPERATIONAL CONDITIONS 2*#, 3, and 4.

ACTION:

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

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

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

a. Performance of a:

1. CHANNEL CHECK ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~a) 12 hours in CONDITION 2*, and~~
~~b) 24 hours in CONDITION 3 or 4.~~

2. CHANNEL CALIBRATION** ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3.0 cps*** with the detector fully inserted.#

*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.
#During initial startup test program, SRM detectors may be partially withdrawn prior to IRM on-scale indication provided that the SRM channels remain on scale above 100 cps and respond to changes in the neutron flux.

INSTRUMENTATION

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.1 Two independent chlorine detection system subsystems shall be OPERABLE with their alarm and trip setpoints adjusted to actuate at a chlorine concentration of less than or equal to 0.5 ppm

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detection subsystem inoperable, restore the inoperable detection system to OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of at least one control room emergency filtration system subsystem in the chlorine isolation mode of operation.

b. With both chlorine detection subsystem inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration system subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.1 Each of the above required chlorine detection system subsystems shall be demonstrated OPERABLE by performance of a~~:~~ CHANNEL CHECK, CHANNEL FUNTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

~~a. CHANNEL CHECK at least once per 12 hours,~~

~~b. CHANNEL FUNCTIONAL TEST at least once per 92 days, and~~

~~c. CHANNEL CALIBRATION at least once per 24 months.~~

TOXIC GAS DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.2 Three independent toxic gas detection system subsystems shall be OPERABLE with their alarm setpoints adjusted to actuate at a toxic gas concentration of less than or equal to:

CHEMICAL	MONITOR SET POINT (ppm)
Ammonia	25
Ethylene Oxide	50
Formaldehyde	5
Vinyl Chloride	10
Phosgene	0.4

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one toxic gas detection subsystem inoperable, place the inoperable subsystem in the tripped condition within 24 hours.

b. With two toxic gas detection system subsystems inoperable, place one inoperable subsystem in the tripped condition within 1 hour, restore one inoperable detection subsystem to OPERABLE status within 7 days, or initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

c. With three toxic gas detection subsystems inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.2 Each of the above required toxic gas detection system subsystems shall be demonstrated OPERABLE by performance of a~~:~~ CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

~~a. CHANNEL CHECK at least once per 12 hours,~~

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

~~c. CHANNEL CALIBRATION at least once per 24 months.~~

INSTRUMENTATION

OFFGAS GAS MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.12 The offgas monitoring instrumentation channels shown in Table 3.3.7.12-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specifications 3.11.2.5 and 3.11.2.6 respectively, are not exceeded.

APPLICABILITY: As shown in Table 3.3.7.12-1

ACTION:

a. With an offgas monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Specification, declare the channel inoperable, and take the ACTION shown in Table 3.3.7.12-1.

b. With less than the minimum number of offgas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.12-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or explain why this inoperability was not corrected in a timely manner in the next Annual Radioactive Effluent Release Report.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each offgas monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies ~~shown~~ specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.12-1.

TABLE 4.3.7.12-1

OFFGAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (5)	SOURCE CHECK (5)	CHANNEL CALIBRATION(5)	CHANNEL FUNCTIONAL TEST (5)	MODES IN WHICH SURVEILLANCE IS REQUIRED
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	~~D~~	N.A.	~~Q~~(3)	~~M~~	**
2. (Deleted)					
3. (Deleted)					
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR (STEAM JET AIR EJECTOR)					
a. Noble gas activity monitor	~~D~~	~~M~~	~~R~~(2)	~~Q~~(1)	**
5. (Deleted)					

TABLE 4.3.7.12-1 (Continued)

TABLE NOTATIONS

* (Deleted)

** During operation of the main condenser steam jet air ejector and offgas treatment system.

*** (Deleted)

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.

2. Circuit failure.

3. Instrument indicates a downscale failure.

4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Institute of Standards and Technology (NIST), previously National Bureau of Standards, or using standards that have been obtained from suppliers that participate in measurement assurance activities with NIST. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(3) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. 0.0 volume percent hydrogen, balance nitrogen, and

2. 4 volume percent hydrogen, balance nitrogen.

(4) (Deleted)

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

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

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

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

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

SURVEILLANCE REQUIREMENTS

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

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

~~TABLE 4.3.9.1-1~~

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

~~TRIP FUNCTION~~	~~CHANNEL CHECK~~	~~CHANNEL FUNCTIONAL TEST~~	~~CHANNEL CALIBRATION~~	~~OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED~~
~~1. Reactor Vessel Water Level High, Level 8~~	~~D~~	~~Q~~	~~R~~	~~1*~~

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~~* With Thermal Power greater than or equal to 25% of Rated Thermal Power.~~

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 DELETED

4.4.1.1.2 DELETED

4.4.1.1.3 Establish a baseline APRM and LPRM** neutron flux noise value within the regions for which monitoring is required (Specification 3.4.1.1, ACTION c) within 2 hours of entering the region for which monitoring is required unless baselining has previously been performed in the region since the last refueling outage.

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

a. Reactor THERMAL POWER is ≤ 76.2% of RATED THERMAL POWER,

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

c. The speed of the operating recirculation pump is ≤ 90% of rated pump speed.

d. Core flow is greater than 39% when THERMAL POWER is within the restricted zone of Figure 3.4.1.1-1.

4.4.1.1.5 With one reactor coolant system recirculation loop not in operation, within 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 30% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow.

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

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

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

The differential temperature requirements of Specification 4.4.1.1.5b. and c. do not apply when the loop not in operation is isolated from the reactor pressure vessel.

**Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. During two recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program while greater than 25% of RATED THERMAL POWER by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when both recirculation loop indicated flows are in compliance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established* pump speed-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established* patterns by more than 10%.

*During the startup test program, data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon the conclusion of the startup test program.

SURVEILLANCE REQUIREMENTS (Continued)

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

1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established* pump speed-loop flow characteristics.

2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from single recirculation loop flow measurements.

3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* single recirculation loop patters by more than 10%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 25% of RATED THERMAL POWER and upon entering single recirculation loop operation.

*During the startup test program, data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon the conclusion of the startup test program.

RECIRCULATION PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of each other with core flow greater than or equal to 70% of rated core flow.

b. 10% of each other with core flow less than 70% of rated core flow.

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

ACTION:

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

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

b. Shutdown one of the recirculation loops within the next 8 hours and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

*See Special Test Exception 3.10.4.

3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of at least 12 of the following reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings:*#

4 safety/relief valves @ 1170 psig ±3%
5 safety/relief valves @ 1180 psig ±3%
5 safety/relief valves @ 1190 psig ±3%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the safety valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. DELETED

c. With one or more safety/relief valve acoustic monitors inoperable, restore the inoperable acoustic monitors to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be 0.20 of the full open noise level## by performance of a:

a. CHANNEL FUNCTIONAL TEST ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program, and a
b. CHANNEL CALIBRATION ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program **.

4.4.2.2 At least 1/2 of the safety relief valves shall be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program, and they shall be rotated such that all 14 safety relief valves are removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations ~~at least once per 54 months~~ in accordance with the Surveillance Frequency Control Program. All safety valves will be recertification tested to meet a ±1% tolerance prior to returning the valves to service.

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

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

\# Up to 2 inoperable valves may be replaced with spare OPERABLE valves with lower setpoints until the next refueling.

Initial setting shall be in accordance with the manufacturer's recommendation. Adjustment to the valve full open noise level shall be accomplished during the startup test program.

ACTIONS (Continued)

F. With any other two or more leak detection systems inoperable other than ACTION E above OR with required Actions and associated Completion Time of ACTIONS A, B, C, D or E not met, be in HOT SHUTDOWN within 12 hours AND in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

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

a. Perform a CHANNEL CHECK of the primary containment atmosphere gaseous radioactivity monitoring system ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

b. Perform a CHANNEL FUNCTIONAL TEST or required leakage detection instrumentation ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

c. Perform a CHANNEL CALIBRATION of required leakage detection instrumentation ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

d. Monitor primary containment pressure ~~once per 12 hours~~ AND ~~monitor~~ primary containment temperature ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

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

a. Monitoring the primary containment atmospheric gaseous radioactivity ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate ~~at least once per eight (8) hours~~ in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

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

a. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program, and

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

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

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the allowable values in Table 3.4.3.2-1 by performance of a~~:~~ CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

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

~~b. CHANNEL CALIBRATION at least once per 24 months.~~

SURVEILLANCE REQUIREMENTS

4.4.4 The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant for:

1. Chlorides ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~a) 72 hours and~~

~~b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.~~

2. Conductivity ~~at least once per 72 hours~~ in accordance with the Surveillance Frequency Control Program.

3. pH ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~a) 72 hours, and~~

~~b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.~~

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable for up to 31 days, obtaining an in-line conductivity measurement ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~1. 4 hours in OPERATIONAL CONDITIONS 1, 2, and 3, and~~

~~2. 24 hours at all other times.~~

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell ~~at least once per:~~ in accordance with the Surveillance Frequency Control Program.

~~1. 7 days, and~~

~~2. 24 hours whenever conductivity is greater than the limit in in Table 3.4.4-1.~~

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

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

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

**Until the specific activity of the primary coolant system is restored to within its limits.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

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

a. A maximum heatup of 100°F in any 1-hour period,

b. A maximum cooldown of 100°F in any 1-hour period,

c. A maximum temperature change of less than or equal to 20°F in any 1-hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange temperature greater than or equal to 70°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figure 3.4.6.1-1 curves A, B or C as applicable, ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curve C within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program during system heatup.

4.4.6.1.3 DELETED

4.4.6.1.4 DELETED

4.4.6.1.5 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 70°F:

a. In OPERATIONAL CONDITION 4 in accordance with the Surveillance Frequency Control Program. ~~when reactor coolant system temperature is:~~

~~1. ≤ 100°F, at least once per 12 hours.~~

~~2. ≤ 90°F, at least once per 30 minutes.~~

b. Within 30 minutes prior to and ~~at least once per 30 minutes~~ in accordance with the Surveillance Frequency Control Program during tensioning of the reactor vessel head bolting studs.

REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1053 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1053 psig, reduce the pressure to less than 1053 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1053 psig ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

*Not applicable during anticipated transients.

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two (2) independent RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

Each independent RHR shutdown cooling subsystem shall consist of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger, not common to the two (2) independent subsystems.

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

ACTION:

a. With less than the above required independent RHR shutdown cooling subsystems OPERABLE, immediately initiate corrective action to return the required independent subsystems to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, verify the availability of at least one alternate method capable of decay heat removal for each inoperable independent RHR shutdown cooling subsystem. Be in at least COLD SHUTDOWN within 24 hours.****

b. With no independent RHR shutdown cooling subsystem in operation, immediately initiate corrective action to return at least one (1) independent subsystem to operation as soon as possible. Within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one independent RHR shutdown cooling subsystem or alternate method shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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*One independent RHR shutdown cooling subsystem may be inoperable for up to 2 hours for surveillance testing provided the other independent subsystem is OPERABLE and in operation.

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

***The independent RHR shutdown cooling subsystem may be removed from operation during hydrostatic testing.

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

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION: #

a. With one (1) or two (2) RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.

b. With no RHR shutdown cooling subsystems in operation and no recirculation pump in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulating by an alternate method; and

   2. Once per hour monitor reactor coolant temperature and pressure.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one (1) RHR shutdown cooling subsystem or recirculation pump is operating or an alternate method shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up two (2) hours per eight hour (8) period.

** One (1) RHR shutdown cooling subsystem may be inoperable for up to two (2) hours for the performance of Surveillances.

*** The shutdown cooling subsystem may be removed from operation during hydrostatic testing.

\# Separate Action entry is allowed for each shutdown cooling subsystem.

SURVEILLANCE REQUIREMENTS

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

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

1. For the CSS, the LPCI system, and the HPCI system:

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

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

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-282 A, B) are closed with power removed from the valve operators.

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

4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.

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

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

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

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

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72-hours.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

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

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

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

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

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid.

d. For the ADS:

1. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

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

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

   c) DELETED

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS

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

4.5.2.2 The core spray system shall be determined OPERABLE ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2a.2.b).

*One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying the water level to be greater than or equal to the required limit at the frequency specified in accordance with the Surveillance Frequency Control Program.~~, as applicable:~~

~~a. 22'0" at least once per 24 hours.~~

~~b. 16'0" at least once per 12 hours.~~

4.5.3.2 With the suppression chamber level less than the ~~above~~ required limit or drained in OPERATIONAL CONDITION 4 or 5*, ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program:

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

b. Verify footnote conditions * to be satisfied.

*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

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

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

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

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

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* See Special Test Exception 3.10.1

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

SURVEILLANCE REQUIREMENTS

4.6.1.3 The primary containment air lock shall be demonstrated OPERABLE:

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

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

c. ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program by verifying that only one door in the air lock can be opened at a time.***

***Except that the airlock doors need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the airlock doors' interlock is tested within 8 hours after the primary containment has been deinerted and provided the shield door to the airlock is maintained locked closed.

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -1.0 and +2.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 145°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell average air temperature greater than 145°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the volumetric average of the temperatures at the following locations and shall be determined to be within the limit ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program:

	Approximate Elevation	Number of Installed Sensors*
a.	330'	3
b.	320'	3
c.	260'	3
d.	248'	6

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

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber purge system may be in operation with the supply and exhaust isolation valves in one supply line and one exhaust line open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With a drywell and/or suppression chamber purge supply and/or exhaust isolation valve open, except as permitted above, close the valve(s) within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8 ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program, verify each primary containment purge valve [18" or 24"] is closed.*, **

* Only required to be met in OPERATIONAL CONDITIONS 1, 2, and 3.
** Not required to be met when the primary containment purge valves are open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require these valves to be open.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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

c. With only one suppression chamber water level indicator OPERABLE and/or with less than eight suppression pool water temperature indicators, one in each of the eight locations OPERABLE, restore the inoperable indicator(s) to OPERABLE status within 7 days or verify suppression chamber water level and/or temperature to be within the limits at least once per 12 hours.

d. With no suppression chamber water level indicators OPERABLE and/or with less than seven suppression pool water temperature indicators covering at least seven locations OPERABLE, restore at least one water level indicator and at least seven water temperature indicators to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

b. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program by verifying the suppression chamber average water temperature to be less than or equal to 95°F, except:

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

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

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

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER 12 hours after suppression chamber average water temperature has exceeded 95°F for more than 24 hours.

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

SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least 8 suppression pool water temperature indicators in at least 8 locations, OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the temperature alarm setpoint for:

~~1. CHANNEL CHECK at least once per 24 hours.~~

~~2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and~~

~~3. CHANNEL CALIBRATION at least once per 24 months,~~

~~with the temperature alarm setpoint for:~~

1. High water temperature:

   a) First setpoint ≤ 95°F

   b) Second setpoint ≤ 105°F

   c) Third setpoint ≤ 110°F

   d) Fourth setpoint ≤ 120°F

d. By verifying at least two suppression chamber water level indicators OPERABLE by performance of a~~:~~ CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the water level alarm setpoint for high water level < 24'1-1/2".

~~1. CHANNEL CHECK at least once per 24 hours,~~

~~2. CHANNEL FUNCTIONAL TEST at least once per 92 days, and~~

~~3. CHANNEL CALIBRATION at least once per 24* months,~~

~~with the water level alarm setpoint for high water level < 24'1-1/2"~~

e. Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verifying that the A/√k calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

f. By conducting a leakage test on the drywell-to-suppression chamber vacuum breakers at a differential pressure of at least 4.0 psi and verifying that the total leakage area A/√k contributed by all vacuum breakers is less than or equal to 24% of the specified limit and the leakage area for an individual set of vacuum breakers is less than or equal to 12% of the specified limit. The vacuum breaker leakage test shall be conducted during each refueling outage for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted.

~~* The CHANNEL CALIBRATION for level transmitters LT-55-2N062B, -2N062F shall be performed at least once per 18 months.~~

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

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

a. One OPERABLE RHR pump, and

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 500 gpm on recirculation flow through the RHR heat exchanger and the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

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

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

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

a. One OPERABLE RHR pump, and

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 10,000 gpm on recirculation flow through the flow path including the RHR heat exchanger and its associated closed bypass valve, the suppression pool and the full flow test line when tested pursuant to Specification 4.0.5.

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

SURVEILLANCE REQUIREMENTS

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

4.6.3.2 Each primary containment automatic isolation valve shall be demonstrated OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

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

4.6.3.4 A representative sample of instrumentation line excess flow check valves shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program, ~~at least once per 24 months such that each valve is tested at least once per every 120 months,~~ by verifying that the valve checks flow.*

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

a. ~~At least once per 31~~ In accordance with the Surveillance Frequency Control Program days by verifying the continuity of the explosive charge.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by removing the explosive squib from the explosive valve, ~~such that each explosive squib in each explosive valve will be tested at least once per 120 months,~~ and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and/or operating life, as applicable.

*The reactor vessel head seal leakage detection line (penetration 29A) excess flow check valve is not required to be tested pursuant to this requirement.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

b. Demonstrated OPERABLE:

1. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program and within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel.

2. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying both position indicators OPERABLE by observing expected valve movement during the cycling test.

3. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

a) Verifying each valve's opening setpoint, from the closed position, to be 0.5 psid ± 5%, and

b) Verifying both position indicators OPERABLE by performance of a CHANNEL CALIBRATION.

c) Verifying that each outboard valve's position indicator is capable of detecting disk displacement ≥0.050", and each inboard valve's position indicator is capable of detecting disk displacement ≥0.120".

3/4.6.5 SECONDARY CONTAINMENT

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Without REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY, restore REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program that the pressure within the reactor enclosure secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program that:

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

   2. At least one door in each access to the reactor enclosure secondary containment is closed.

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

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

   1. Verifying that one standby gas treatment subsystem will draw down the reactor enclosure secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 916 seconds with the reactor enclosure recirc system in operation, and

   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the reactor enclosure secondary containment at a flow rate not exceeding 2500 cfm with wind speeds of $\leq$ 7.0 mph as measured on the wind instrument on Tower 1, elevation 30' or, if that instrument is unavailable, Tower 2, elevation 159'.

3/4.6.5 SECONDARY CONTAINMENT

REFUELING AREA SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

Without REFUELING AREA SECONDARY CONTAINMENT INTEGRITY, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program that the pressure within the refueling area secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program that:

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

   2. At least one door in each access to the refueling area secondary containment is closed.

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

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program:

   Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the refueling area secondary containment at a flow rate not exceeding 764 cfm.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.1 The reactor enclosure secondary containment ventilation system automatic isolation valves shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more of the reactor secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

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

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

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

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 Each reactor enclosure secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.2 The refueling area secondary containment ventilation system automatic isolation valves shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

With one or more of the refueling area secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

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

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

Otherwise, in OPERATIONAL CONDITION*, suspend handling of irradiated fuel in the refueling area secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.2.2 Each refueling area secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

SURVEILLANCE REQUIREMENTS (Continued)

b. ~~At least once per 24* months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 5764 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

3. Verify that when the fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III) when tested in accordance with ANSI N510-1980.

4. Verify that the pressure drop across the refueling area to SGTS prefilter is less than 0.25 inches water gage while operating at a flow rate of 2400 cfm ± 10%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 9.1 inches water gauge while operating the filter train at a flow rate of 8400 cfm ± 10%.

~~*Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52, Revision 2, March 1978~~.

REACTOR ENCLOSURE RECIRCULATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.4 Two independent reactor enclosure recirculation subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one reactor enclosure recirculation subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both reactor enclosure recirculation subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.4 Each reactor enclosure recirculation subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates properly.

b. ~~At least once per 24* months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 60,000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

3. Verifying a subsystem flow rate of 60,000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980.

~~*Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52 Revision 2, March 1978.~~

SURVEILLANCE REQUIREMENTS (Continued)

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) an a relative humidity of 70%.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the filter train at a flow rate of 60,000 cfm ± 10%, verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

2. Verifying that the filter train starts and the isolation valves which take suction on and return to the reactor enclosure open on each of the following test signals:

a. Manual initiation from the control room, and

b. Simulated automatic initiation signal.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 60,000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydro-carbon refrigerant test gas while operating the system at a flow rate of 60,000 cfm ± 10%.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

PRIMARY CONTAINMENT HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.6.1 Two independent primary containment hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one primary containment hydrogen recombiner system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.1 Each primary containment hydrogen recombiner system shall be demonstrated OPERABLE:

a. ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program by performance of:

   1. A CHANNEL CHECK of all Control Room Recombiner Instrumentation.

   2. A Trickle Heat Circuit check.

   3. A Heater Coil Check.

   4. A verification of valve operation by stroking all the valves to their proper positions.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

   1. Performing a CHANNEL CALIBRATION of all control room recombiner instrumentation and control circuits.

   2. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test within 30 minutes following the below required functional test. The resistance to ground for any heater phase shall be greater than or equal to one (1) megohm.

   3. Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure; i.e., loose wiring or structural connections, deposits of foreign materials, etc.

   4. Verifying during a recombiner system functional test that the minimum heater outlet gas temperature increases to greater than or equal to 1150°F within 120 minutes and maintained for at least one hour.

c. By measuring the system leakage rate:

   1. As a part of the overall integrated leakage rate test required by Specification 3.6.1.2, or

   2. By measuring the leakage rate of the system outside of the containment isolation valves at P_a, 44.0 psig, on the schedule required by Specification 4.6.1.2, and including the measured leakage as a part of the leakage determined in accordance with Specification 4.6.1.2.

DRYWELL HYDROGEN MIXING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.2 Four independent drywell unit cooler hydrogen mixing subsystems (2AV212, 2BV212, 2GV212, 2HV212) shall be OPERABLE with each subsystem consisting of one unit cooler fan.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell unit cooler hydrogen mixing subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 Each drywell unit cooler hydrogen mixing subsystem shall be demonstrated OPERABLE ~~at least once per 92 days~~ in accordance with the Surveillance Frequency Control Program by:

a. Starting the system from the control room, and

b. Verifying that the system operates for at least 15 minutes.

DRYWELL AND SUPPRESSION CHAMBER OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

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

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

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

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.6.3 The drywell and suppression chamber oxygen concentration shall be verified to be within the limit within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER and ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program thereafter.

*See Special Test Exception 3.10.5.
**Specification 3.6.1.8 is applicable during this 24 hour period.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

5. With two RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With three RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

7. With four RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required residual heat removal service water system subsystem(s) shall be demonstrated OPERABLE:

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

*A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

4. With three ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With four ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5:

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated safety related equipment inoperable and take the ACTION required by Specifications 3.5.2 and 3.8.1.2.

c. In OPERATIONAL CONDITION *

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or verify adequate cooling remains available for the diesel generators required to be OPERABLE or declare the associated diesel genera-tor(s) inoperable and take the ACTION required by Specifica-tion 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENT

4.7.1.2 At least the above required emergency service water system loop(s) shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each automatic valve actuates to its correct position on its appropriate ESW pump start signal.

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

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* When handling irradiated fuel in the secondary containment.

** An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, than the ESW pump/diesel generator pair is inoperable.

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The spray pond shall be OPERABLE with:

a. A minimum pond water level at or above elevation 250'-10" Mean Sea Level, and

b. A pond water temperature of less than or equal to 88°F.

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

ACTION:

With the requirements of the above specification not satisfied:

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

b. In OPERATIONAL CONDITION 4 or 5, declare the RHRSW system and the emergency service water system inoperable and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2.

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

SURVEILLANCE REQUIREMENTS

4.7.1.3 The spray pond shall be determined OPERABLE:

a. By verifying the pond water level to be greater than its limit ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program.

b. By verifying the water surface temperature (within the upper two feet of the surface) to be less than or equal to 88°F~~:~~ in accordance with the Surveillance Frequency Control Program.

~~1. at least once per 4 hours when the spray pond temperature is greater than or equal to 80°F; and~~

~~2. at least once per 2 hours when the spray pond temperature is greater than or equal to 85°F; and~~

~~3. at least once per 24 hours when the spray pond temperature is greater than 32°F.~~

c. By verifying all piping above the frost line is drained:

1. within one (1) hour after being used when ambient air temperature is below 40°F; or

2. when ambient air temperature falls below 40°F if the piping has not been previously drained.

*When handling irradiated fuel in the secondary containment.

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency fresh air supply subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 12 hours~~ In accordance with the Surveillance Frequency Control Program by verifying the control room air tempera-ture to be less than or equal to 85°F effective temperature.

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

c. ~~At least once per 24* months~~ In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 3000 cfm ± 10%.

~~* Surveillance interval is an exception to the guidance provided in Regulatory Guide 1.52, Revision 2, March 1978.~~

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

3. Verifying a subsystem flow rate of 3000 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

e. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the subsystem at a flow rate of 3000 cfm ± 10%; verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

2. Verifying that on each of the below chlorine isolation mode actuation test signals, the subsystem automatically switches to the chlorine isolation mode of operation and the isolation valves close within 5 seconds:

   a) Outside air intake high chlorine, and

   b) Manual initiation from the control room.

3. Verifying that on each of the below radiation isolation mode actuation test signals, the subsystem automatically switches to the radiation isolation mode of operation and the control room is maintained at a positive pressure of at least 1/8 inch water gauge relative to the turbine enclosure and auxiliary equipment room and outside atmosphere during subsystem operation with an outdoor air flow rate less than or equal to 525 cfm:

   a) Outside air intake high radiation, and

   b) Manual initiation from control room.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

b. In the event the RCIC system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

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

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

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

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

b. ~~At least once per 92 days~~ In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by:

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

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

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

4. Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

3/4.7.5 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

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

   1. Decontaminate and repair the sealed source, or

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

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

a. The licensee, or

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

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

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

a. Sources in use - ~~At least once per 6 months~~ In accordance with the Surveillance Frequency Control Program for all sealed sources containing radioactive material:

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

   2. In any form other than gas.

3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE as determined by the number of operable main turbine bypass valves being greater than or equal to that specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or take the ACTION required by Specification 3.2.3.c.

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE ~~at least once per~~ in accordance with the Surveillance Frequency Control Program:

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

b. ~~24 months b~~By performing a system functional test which includes simulated automatic actuation, and by verifying that each automatic valve actuates to its correct position, and

c. ~~24 months b~~By determining TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to the value specified in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

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

a. Determined OPERABLE ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

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

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

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

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

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

4. Verify that the diesel can start* and gradually accelerate to synchronous speed with generator voltage and frequency at 4280 ± 120 volts and 60 ± 1.2 Hz.

5. Verify diesel is synchronized, gradually loaded* to an indicated 2700-2800 kW** and operates with this load for at least 60 minutes.

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

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 225 psig.

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

SURVEILLANCE REQUIREMENTS (Continued)

b. By removing accumulated water:

1) From the day tank ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program and after each occasion when the diesel is operated for greater than 1 hour, and

2) From the storage tank ~~at least once per 31 days~~ in accordance with the Surveillance Frequency Control Program.

c. By sampling new fuel oil in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1) By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

a) An API Gravity of within 0.3 degrees at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

c) A flash point equal to or greater than 125°F, and

d) A clear and bright appearance with proper color when tested in accordance with ASTM D4176-82.

2) By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

d. ~~At least once every 31 days~~ In accordance with the Surveillance Frequency Control Program by obtaining a sample of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A, except that the filters specified in ASTM D2276-78, Sections 5.1.6 and 5.1.7, may have a nominal pore size of up to three (3) microns.

e. ~~At the following frequency~~ In accordance with the Surveillance Frequency Control Program by:

1) Deleted

2) ~~Every 24 months v~~Verifying each diesel generator's capability to reject a load of greater than or equal to that of its single largest post-accident load while maintaining voltage at 4285 ± 420 volts and frequency at 60 ± 1.2 hz and after steady state conditions are reached, voltage is maintained at 4280 ± 120 volts.

SURVEILLANCE REQUIREMENTS (Continued)

3. ~~Every 24 months v~~Verifying the diesel generator capability to reject a load of 2850 kW without tripping. The generator voltage shall not exceed 4784 volts during and following the load rejection.

4. ~~Every 24 months s~~Simulating a loss-of-offsite power by itself, and:

   a) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency buses within 10 seconds, energizes the auto-connected loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

5. ~~Every 24 months v~~Verifying that on an ECCS actuation test signal, without loss-of-offsite power, the diesel generator starts* on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. ~~Every 24 months s~~Simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, and:

   a) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency buses within 10 seconds, energizes the auto-connected shutdown loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

7. ~~Every 24 months v~~Verifying that all automatic diesel generator trips, except engine overspeed and generator differential overcurrent are automatically bypassed upon an ECCS actuation signal.

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warm up procedures, and as applicable regarding loading and shutdown recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

8. a) ~~Every 24 months v~~Verifying the diesel generator operates* for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to an indicated 2950-3050 kW** and during the remaining 22 hours of this test, the diesel generator shall be loaded to an indicated 2700-2800 kW**.

   b) ~~Every 24 months v~~Verifying that, within 5 minutes of shutting down the diesel generator after the diesel generator has operated* for at least 2 hours at an indicated 2700-2800 kW**, the diesel generator starts*. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal.

9. ~~Every 24 months v~~Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 3100 kW.

10. ~~Every 24 months v~~Verifying the diesel generator's capability to:

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

    b) Transfer its loads to the offsite power source, and

    c) Be restored to its standby status.

11. ~~Every 24 months v~~Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

12. ~~Every 24 months v~~Verifying that the automatic load sequence timers are OPERABLE with the interval between each load block within ± 10% of its design interval.

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* This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

** This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

SURVEILLANCE REQUIREMENTS (Continued)

13. ~~Every 24 months v~~Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

    a) Control Room Switch In Pull-To-Lock (With Local/Remote Switch in Remote)

    b) Local/Remote Switch in Local.

    c) Emergency Stop

f. ~~At least once per 10 years~~ In accordance with the Surveillance Frequency Control Program or after any modifications which could affect diesel generator interdependence by starting* all four diesel generators simultaneously, during shutdown, and verifying that all four diesel generators accelerate to at least 882 rpm in less than or equal to 10 seconds.

g. ~~At least once per 10 years~~ In accordance with the Surveillance Frequency Control Program by:

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

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

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

h. ~~At least once per 184 days~~ In accordance with the Surveillance Frequency Control Program the diesel generator shall be started* and verified to accelerate to synchronous speed in less than or equal to 10 seconds. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual***

b) Simulated loss-of-offsite power by itself.

c) Simulated loss-of-offsite power in conjunction with an ECCS actuation test signal.

d) An ECCS actuation test signal by itself.

The generator shall be manually synchronized to its appropriate emergency bus, loaded to an indicated 2700-2800 KW** in less than or equal to 200 seconds, and operate for at least 60 minutes. This test, if it is performed so it coincides with the testing required by Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5, may also serve to concurrently meet those requirements as well.

4.8.1.1.3 Reports - All diesel generator failures, valid or nonvalid, shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2 within 30 days. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

***If diesel generator started manually from the control room, 10 seconds after the automatic prelube period.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

NUMBER OF FAILURES IN LAST 20 VALID DEMANDS*	TEST FREQUENCY
less than or equal to 1 or,	~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program
greater than or equal to 2**	~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program

*Criteria for determining number of failures and number of valid demands shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, but determined on a per diesel generator basis.

**The associated test frequency shall be maintained until seven consecutive failure free demands have been performed and the number of failures in the last 20 demands have been reduced to one.

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per 7 days~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each Division 1 and 2 battery float current is ≤ 2 amps, and Division 3 and 4 battery float current is ≤ 1 amp when battery terminal voltage is greater than or equal to the minimum established float voltage of 4.8.2.1.a.2, and

2. Total battery terminal voltage for each 125-volt battery is greater than or equal to the minimum established float voltage.

b. ~~At least once per 31 days~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each battery pilot cell voltage is ≥ 2.07 volts,

2. Each battery connected cell electrolyte level is greater than or equal to minimum established design limits, and

3. The electrolyte temperature of each pilot cell is greater than or equal to minimum established design limits.

c. ~~At least once per 92 days~~ In accordance with the Surveillance Frequency Control Program by verifying that each battery connected cell voltage is ≥ 2.07 volts.

d. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by verifying that:

1. The battery chargers will supply the currents listed below at greater than or equal to the minimum established float voltage for at least 4 hours:

Charger	Current (Amperes)
2BCA1	300
2BCA2	300
2BCB1	300
2BCB2	300
2BCC	75
2BCD	75

2. The battery capacity is adequate to supply and maintain in OPERABLE status the required emergency loads for the design duty cycle when subjected to a battery service test.

e. ~~At least once per 60 months~~ In accordance with the Surveillance Frequency Control Program by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test or modified performance discharge test. The modified performance discharge test may be performed in lieu of the battery service test (Specification 4.8.2.1.d.2).

f. Performance discharge tests or modified performance discharge tests of battery capacity shall be given as follows:

1. ~~At least once per 12 months~~ In accordance with the Surveillance Frequency Control Program when:
   (a) The battery shows degradation or
   (b) The battery has reached 85% of expected life with battery capacity < 100% of manufacturer's rating, and

2. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program when battery has reached 85% of expected life with battery capacity ≥ 100% of manufacturer's rating.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one of the above required Unit 2 A.C. distribution system divisions not energized, reenergize the division within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 2 D.C. distribution system divisions not energized, reenergize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any of the above required Unit 1 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system divisions shall be determined energized ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. With less than two divisions of the above required Unit 2 D.C. distribution systems energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. With any of the above required Unit 1 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system divisions shall be determined energized ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

MOTOR-OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of all Class 1E motor operated valves shall be either:

a. Continously bypassed for all valves with maintained position control switches; or,

b. Bypassed only under accident conditions for all valves with spring-return-to-normal control switches.

APPLICABILITY: Whenever the motor-operated valve is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required valves not bypassed continuously or only under accident conditions, as applicable, restore the thermal overload bypass within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection for the above required valves which are continuously bypassed and temporarily placed in force only when the valve motor is undergoing periodic or maintenance testing shall be verified to be bypassed following periodic or maintenance testing during which the thermal overload protection was temporarily placed in force.

4.8.4.2.2 ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program, a CHANNEL FUNCTIONAL TEST of all those valves which are bypassed only under accident conditions (valves with spring- return-to-normal control switches) shall be performed to verify that the thermal overload protection will be bypassed under accident conditions.

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.3 Two reactor protection system (RPS) electric power monitoring channels for each inservice RPS Inverter or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

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

b. With both RPS electric power monitoring channels for an inservice RPS Inverter or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 24 hours or remove the associated RPS Inverter or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

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

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

b. ~~At least once per 24 months~~ In accordance with the Surveillance Frequency Control Program by demonstrating the OPERABILITY of overvoltage, undervoltage, and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic, and output circuit breakers and verifying the following Allowable Values.

1. Overvoltage ≤ 127.6 VAC,

2. Undervoltage ≥ 110.7 VAC,

3. Underfrequency ≥ 57.05 Hz.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks* shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during control rod withdrawal or CORE ALTERATIONS, as applicable.

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks* that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

*The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least two source range monitor (SRM) channels* shall be OPERABLE and inserted to the normal operating level with:

a. Continuous visual indication in the control room,

b. At least one with audible alarm in the control room,

c. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

d. Unless adequate SHUTDOWN MARGIN has been demonstrated, the "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn.**

APPLICABILITY: OPERATIONAL CONDITION 5.***

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. ~~At least once per 12 hours~~ In accordance with the Surveillance Frequency Control Program:

1. Performance of a CHANNEL CHECK,

2. Verifying the detectors are inserted to the normal operating level, and

3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

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*These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core. The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

***See Special Test Exception, Specification 3/4.10.7.

SURVEILLANCE REQUIREMENTS (Continued)

b. Performance of a CHANNEL FUNCTIONAL TEST ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

c. Verifying that the channel count rate is at least 3.0 cps:*

1. Prior to control rod withdrawal,

2. Prior to ~~and at least once per 12 hours during~~ CORE ALTERATIONS, and

3. ~~At least once per 24 hours~~ In accordance with the Surveillance Frequency Control Program.

d. Verifying, within 8 hours prior to and ~~at least once per 12 hours during~~ in accordance with the Surveillance Frequency Control Program, that the RPS circuitry "shorting links" have been removed during:

1. The time any control rod is withdrawn**, unless adequate shutdown margin has been demonstrated, or

2. Shutdown margin demonstrations.

*May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1. These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS, except that one control rod may be withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

*Except control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**See Special Test Exception 3.10.3.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communication shall be maintained between the control room and refueling floor personnel.

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.*

ACTION:

When direct communication between the control room and refueling floor personnel cannot be maintained, immediately suspend CORE ALTERATIONS.*

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communication between the control room and refueling floor personnel shall be demonstrated ~~at least once per 12 hours~~ during CORE ALTERATIONS in accordance with the Surveillance Frequency Control Program.*

*Except movement of control rods with their normal drive system.

3/4.9.7 CRANE TRAVEL-SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 1200 pounds shall be prohibited from travel over fuel assemblies in the spent fuel storage pool racks.

APPLICABILITY: With fuel assemblies in the spent fuel storage pool racks.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 Crane interlocks which prevent crane travel over fuel assemblies in the spent fuel storage pool racks shall be demonstrated OPERABLE within 7 days prior to and ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during crane operation.

3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least 22 feet of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program during handling of fuel assemblies or control rods within the reactor pressure vessel.

3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.9 At least 22 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage pool area after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the spent fuel storage pool shall be determined to be at least at its minimum required depth ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program thereafter until a control rod and associ-ated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

SURVEILLANCE REQUIREMENTS

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and ~~at least once per 24 hours~~ in accordance with the Surveillance Frequency Control Program thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 One (1) RHR shutdown cooling subsystem shall be OPERABLE and in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With the required RHR shutdown cooling subsystem inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available.

b. With the required action and associated completion time of Action "a" above not met.

   1. Immediately suspend loading of irradiated fuel assemblies into the reactor pressure vessel; and

   2. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   3. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   4. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* The required RHR shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and one (1) RHR shutdown cooling subsystem shall be in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With one (1) or two (2) required RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable required RHR shutdown cooling subsystem.

b. With the required action and associated completion time of Action "a" above not met:

   1. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   2. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   3. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program.

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* The required operating shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3, and 3.9.1 and Table 1.2 may be suspended to permit the reactor pressure vessel closure head and the drywell head to be removed and the primary containment air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during low power PHYSICS TESTS.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3, and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

a. The source range monitors are OPERABLE with the RPS circuitry "shorting links" removed per Specification 3.9.2.

b. The rod worth minimizer is OPERABLE per Specification 3.1.4.1 and is programmed for the shutdown margin demonstration, or conformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The "continuous rod withdrawal" control shall not be used during out-of-sequence movement of the control rods.

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

4.10.3 Within 30 minutes prior to and ~~at least once per 12 hours~~ in accordance with the Surveillance Frequency Control Program during the performance of a shutdown margin demonstration, verify that;

a. The source range monitors are OPERABLE per Specification 3.9.2,

b. The rod worth minimizer is OPERABLE with the required program per Specification 3.1.4.1 or a second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown margin demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

3/4.10.4 RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER, or

b. The Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS and the Startup Test Program.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS and the Startup Test Program.

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS.

3/4.10.5 OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.10.5 The provisions of Specification 3.6.6.3 may be suspended until completion of the Startup Test Program or the reactor has operated for 120 Effective Full Power Days.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION

With the requirements of the above specification not satisfied, be in at least STARTUP within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.5 The Effective Full Power Days of operation shall be verified to be less than 120, by calculation, ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program during the Startup Test Program.

3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits ~~at least once per hour~~ in accordance with the Surveillance Frequency Control Program during training startups.

RADIOACTIVE EFFLUENTS

LIQUID HOLDUP TANKS

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in any outside temporary tanks shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit and describe the events leading to this condition in the next Annual Radioactive Effluent Release Report.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each of the above tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents ~~at least once per 7 days~~ in accordance with the Surveillance Frequency Control Program when radio-active materials are being added to the tank.

MAIN CONDENSER

LIMITING CONDITION FOR OPERATION

3.11.2.6 The rate of the sum of the activities of the noble gases Kr-85m, Kr-87, Kr-88, Xe-133, Xe-135, and Xe-138 measured at the recombiner after-condenser discharge shall be limited to less than or equal to 330 millicuries/second.

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

ACTION:

With the rate of the sum of the activities of the specified noble gases at the recombiner after-condenser discharge exceeding 330 millicuries/second, restore the gross radioactivity rate to within its limit within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.11.2.6.1 The rate of the sum of the activities of noble gases at the recombiner after-condenser discharge shall be continuously monitored in accordance with Specification 3.3.7.12.

4.11.2.6.2 The rate of the sum of the activities of the specified noble gases from the recombiner after-condenser discharge shall be determined to be within the limits of Specification 3.11.2.6 at the following frequencies by performing an isotopic analysis of a representative sample of gases taken at the recombiner after condenser discharge:

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

b. Within 4 hours following an increase, as indicated by the Main Condenser Off-Gas Pretreatment Radioactivity Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level or air in-leakage, in the nominal steady-state fission gas release from the primary coolant.

c. The provisons of Specification 4.0.4 are not applicable.

*When the main condenser air ejector is in operation.

CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances ~~intervals~~ are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 Topical Report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume ~~once each 24 hours~~ assures that the solution is available for use.

Replacement of the explosive charges in the valves ~~at regular intervals~~ will assure that these valves will not fail because of deterioration of the charges.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NECO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. ~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

Actions a, b and c define the action(s) required when RPS channels are discovered to be inoperable. For those actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the ~~specified~~ frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions (Table 3.3.1-2, Items 2.b and 2.c). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11XOX relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11XOX relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The *levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variable following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The ~~specified~~ surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor has been determined in accordance with the Surveillance Frequency Control Program ~~GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specification," as approved by the NRC and documented in the SER (letter to R. D. Binz, IV, from C. E. Rossi dated July 21, 1992)~~.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A. The Unit 1 RHR transfer switches are included only due to their potential impact on the RHRSW system, which is common to both units.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Drywell and containment hydrogen and oxygen analyzers are Category I instruments provided to detect high hydrogen or oxygen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions.

When two hydrogen monitor channels are inoperable, one hydrogen monitor channel must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit; the length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit; and the availability of the hydrogen recombiners, the Containment Purge System, and the Post Accident Sampling Systems.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 CHLORINE AND TOXIC GAS DETECTION SYSTEMS

The OPERABILITY of the chlorine and toxic gas detection systems ensures that an accidental chlorine and/or toxic gas release will be detected promptly and the necessary protective actions will be automatically initiated for chlorine and manually initiated for toxic gas to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the chlorine isolation mode of operation to provide the required protection. Upon detection of a high concentration of toxic gas, the control room emergency ventilation system will manually be placed in the chlorine isolation mode of operation to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release," February 1975.

There are three toxic gas detection subsystems. The high toxic chemical concentration alarm in the Main Control Room annunciates when two of the three subsystems detect a high toxic gas concentration. An Operate/Inop keylock switch is provided for each subsystem which allows an individual subsystem to be placed in the tripped condition. Placing the keylock switch in the INOP position initiates one of the two inputs required to initiate the alarm in the Main Control Room.

~~Specified s~~Surveillance intervals have been determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

RECIRCULATION SYSTEM (Continued)

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduced since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron flux noise level obtained at a specific core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline data taken at lower rod lines (i.e., lower power) will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/ relief valves is required to limit reactor pressure to within ASME III allow-able values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pres-sure tested and stored in accordance with manufacturers recommendations ~~in~~ at the ~~specified~~ frequency specified in the Surveillance Frequency Control Program.

ACTIONS (Continued)

B. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment at a more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, Primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. If any required ACTION of Conditions A, B, C, D or E cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a

This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. ~~The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.~~

SURVEILLANCE REQUIREMENTS (Continued)

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. ~~The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.~~

SR 4.4.3.1.c
This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. ~~The Frequency of 24 months is for a typical refueling cycle and considers channel reliability. Operating experience has proven this frequency to be acceptable.~~

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage. Operating experience has proven this frequency to be acceptable.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3
4. LGS UFSAR, Section 5.2.5.2.1.5
5. LGS UFSAR, Section 5.2.5.2.1.4
6. LGS UFSAR, Section 5.2.5.2.1.1(2)
7. GEAP-5620, April 1968.
8. NUREG-75/067, October 1975.
9. LGS UFSAR, Section 5.2.5.6.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

ECCS - OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS sub-system out-of-service time allowances.

Verification ~~every 31 days~~ that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply. ~~The 31 day Frequency takes into consideration administrative controls over operation of the gas system and alarms for low gas pressure.~~

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to ≤ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. ~~The 31-day Frequency is consistent with other PCIV requirements.~~

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested ~~at least once every 10 years~~ in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. ~~The 10 year interval is based on other performance-based testing programs.~~ Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system ~~once per 24 months~~ in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA or refueling accident (SGTS only). The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA and refueling accident analyses. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS is common to Unit 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses, therefore the inoperability of these Unit 1 supplies are addressed in the SGTS ACTION statements in order to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 Technical Specifications for SGTS and AC electrical power supply out of service condition combinations.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Supplies, March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed ~~at least once per 24 months~~ in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450-1995. ~~The 7-day Frequency is consistent with IEEE-450-1995.~~

This Surveillance Requirement states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained the Actions of LCO 3.8.2.1, Action b., are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). ~~The 7-day Frequency is consistent with manufacturer recommendations and IEEE Standard 450-1995.~~

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V. ~~The Frequency for cell voltage verification every 31 days for pilot cell, and 92 days for each connected cell, is consistent with IEEE Standard 450-1995.~~

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. ~~The Frequency is consistent with IEEE Standard 450-1995.~~

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. ~~The Frequency is consistent with IEEE Standard 450-1995.~~

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

i. Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries For Stationary Applications," of the following:

a. Actions to restore battery cells with float voltage < 2.13 volts, and

b. Actions to equalize and test battery cells that have been discovered with electrolyte level below the minimum established design limit.

j. Surveillance Frequency Control Program

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

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

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

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

ATTACHMENT 4

LICENSE AMENDMENT REQUEST

LIMERICK GENERATING STATION, UNITS 1 AND 2
DOCKET NOS. 50-352 AND 50-353

RELOCATION OF SURVEILLANCE TEST INTERVALS FROM THE TECHNICAL SPECIFICATIONS TO A LICENSEE-CONTROLLED PROGRAM

SUMMARY OF EXAMPLE SURVEILLANCE TEST INTERVAL EVALUATIONS

SUMMARY OF EXAMPLE SURVEILLANCE TEST INTERVAL EVALUATIONS

This License Amendment Request (LAR) for Limerick Generating Station (LGS), Units 1 and 2, is being submitted as a pilot submittal in support of the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b. This LAR is predicated on NRC approval of a risk-informed process and methodology developed by the BWROG Risk Informed Technical Specifications (RITS) Committee in concert with the Nuclear Energy Institute (NEI) for control of changes to surveillance test intervals (STIs) associated with Technical Specifications (TS) surveillance requirements. The details of this risk-informed process and methodology are being submitted separately to the NRC for review and approval as part of Technical Specification Task Force (TSTF) 425; however, a summary of the proposed risk-informed methodology is provided below. A summary of the results of several example STI evaluations using the proposed risk-informed methodology is also provided below.

NOTE: in the course of this attachment, the terms surveillance test interval, surveillance interval, interval, surveillance requirement frequency, surveillance frequency, and frequency may be used interchangeably.

STI Revision Process

A key aspect of the proposed risk-informed STI revision process involves the categorization of the associated structures, systems, and components (SSCs) into high safety significance (HSS) or low safety significance (LSS). Once categorized, revised STIs are developed based on risk insights from the Probabilistic Risk Assessment (PRA) model, in addition to the plant operational experience, and other qualitative factors identified below.

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

1. Each STI revision is reviewed to determine whether there are any commitments made to the NRC that may prohibit changing the interval. If there are no related commitments, or the commitments may be changed using a commitment change process based on NRC endorsed guidance, then evaluation of the STI revision would proceed. If a commitment exists and the commitment change process does not permit the change, then the STI revision would not be implemented.

2. A qualitative analysis is performed for each STI revision that involves the following considerations:
   - surveillance test and performance (operation and maintenance) history of the components and system associated with the STI revision,
   - Maintenance Rule unavailability review,
   - past industry and plant-specific operating experience with the functions affected by the proposed revisions,
   - vendor-specified maintenance frequency,
   - American Society of Mechanical Engineers (ASME) and other code-specified test interval,
   - the impact on defense-in-depth protection,
   - the impact of systems not quantified using the internal events PRA,
   - the impact of systems for which large early release frequency (LERF) results are not available,

- the impact of systems for which external events and shutdown PRA are not available, and
- uncertainty associated with the quantitative (PRA) process.

3. Each STI revision is reviewed by an Integrated Decisionmaking Panel which is similar to an Expert Panel used for Maintenance Rule implementation, but with the addition of specialists with experience in surveillance tests and system or component reliability. After the Integrated Decisionmaking Panel approves the STI revision, the change is implemented and documented for future audits by the NRC. If the Integrated Decisionmaking Panel does not approve the STI revision, the STI value is left unchanged.

4. Performance monitoring is conducted commensurate with the relative safety significance of the SSC associated with the STI. For LSS components (LSSCs), no additional monitoring is necessary beyond that already conducted under the Maintenance Rule. For HSS components (HSSCs), additional monitoring may be necessary. The performance monitoring helps to confirm that no failure mechanisms related to the revised test interval become important enough to alter the failure rate assumed in the justification of the changes. Secondly, performance monitoring, to the extent practical, ensures that adequate component capability exists relative to design-basis conditions, such that component operating characteristics, over time, do not result in reaching a point of insufficient margin before the next scheduled test activity. Two key attributes of the performance monitoring are: (1) the test frequency is sufficient to provide meaningful data, and (2) the testing methods, procedures, and analysis are adequately developed to ensure that performance degradation is detected.

5. The Integrated Decisionmaking Panel is responsible for periodic review of performance monitoring results. Any changes to STIs identified by the Integrated Decisionmaking Panel are recycled into the STI revision process and performance monitoring is continued.

For HSSCs, in addition to the above steps, the PRA is used to quantify the effect of a proposed individual STI revision compared to Regulatory Guideline 1.174 acceptance criteria, and includes, as appropriate:

- internal events Level 1 (core damage frequency (CDF)) PRA model impacts,
- internal events Level 2 (LERF) PRA model impacts,
- fire risk impacts,
- seismic risk impacts, and
- shutdown risk impacts.

For LSSCs, very low risk impact is expected to result from the revised test intervals. Also, the cumulative impact of all risk-informed STI revisions on all PRAs (i.e., internal events, external events and shutdown) is compared to the risk acceptance criteria in Regulatory Guide 1.174. For those cases where the STI can not be modeled in the plant PRA, a bounding analysis is performed to provide some indication of the impact on the PRA results. Bounding analyses are either quantitative carried out with available PRA models or qualitative using deterministic considerations.

Selection of the Example STIs

The following information describes the selection of specific candidate STIs that were used as examples for exercising the BWROG Risk-Informed Initiative 5b methodology.

Input was received from various site organizations, including Operations, Outage Management, Work Management, Health Physics and Engineering. The criteria used for compiling the initial list of candidates was based on the potential benefits in the following areas:

1. reactivity management,
2. maintaining dose as low as reasonably achievable (ALARA),
3. burden reduction (resources),
4. outage impact (outage work control),
5. work management simplification (on-line work control),
6. production risk, and
7. reducing wear and tear on the SSC.

The initial list of STI candidates were then grouped into the five categories below related to the LGS PRA model:

1. PRA modeled – HSS,
2. PRA modeled – LSS,
3. PRA not modeled but could be – HSS,
4. PRA not modeled but could be – LSS, and
5. PRA modeling not practical (qualitative evaluation only).

The selection of STI candidates in these categories was intended to provide the opportunity to exercise all possible legs of the risk-informed methodology. The STIs chosen are discussed below.

Example STI Evaluations

The following information provides a summary of the results of the example STI evaluations using the risk-informed process and methodology for controlling changes to STIs. Completed documentation for the example STI evaluations is available for NRC review on site.

STI #1 – Control Rod Drive (CRD) Exercise Test

LGS TS Surveillance Requirement 4.1.3.1.2.a requires, when above the preset power level of the Rod Worth Minimizer, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated operable by moving each control rod at least one notch at least once per 7 days. The recommended change being evaluated would extend this STI from 7 days to 31 days.

Maintenance Rule (MRule) Classification

The SSC was assessed by the Maintenance Rule Expert Panel to be risk significant. Individual control rods are not modeled in the LGS PRA model. As a result, the control rod drive (CRD) system is only implicitly modeled by the PRA. The system is modeled by one basic event representing the failure of the entire system. Comparison of system level terms to train level criteria as defined in NUMARC 93-01 (Ref. 1) does not provide a useful indication of the system's risk significance. The system is an initiator for failure to scram in the PRA model.

LGS CRD system is both safety-related and safety significant yielding a Risk-Informed Safety Classification (RISC) of RISC-1 per NEI 00-04 (Ref. 2), Rev. D, Figure 1-1. The Risk-Informed Categorization Process (Figure 2-1 of NEI 00-04) would yield a HSS categorization as a worst case result. Since the LGS Maintenance Rule Expert Panel has already classified this system as risk significant, compliance with NEI 00-04 is achieved. The MRule HSS classification is retained as permitted by the Initiative 5b methodology.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the Updated Final Safety Analysis Report (UFSAR) and the LGS commitment tracking database. There is one item impacted by the proposed STI change. The NRC Safety Evaluation Report (SER) for Unit 1 TS Amendment 42 (Ref. 3) credits the use of weekly control rod exercise testing to detect failures of the drive water and exhaust water header manual isolation valves. A failure of these valves would still be detected by performing monthly testing. More important, however, is that a failure of either the drive water or exhaust water header isolation valves cannot impact the scram function of the control rod drive mechanism. Therefore, this item would not be an obstacle to the proposed STI change.

The results of surveillance tests from January 1, 1998 through September 25, 2003, were reviewed. No control rod in either Unit 1 or Unit 2 was unable to be successfully repositioned during testing. Despite the fact that there was never an instance in the review period when a control rod was unable to be repositioned, control rod motion problems have been experienced. The control rod motion problems are typically a result of fuel channel bow interference or normal, age-related internal seal degradation. Channel bow interference has been detected during routine scram time testing and when exercising control rods in preparation for plant startup. It is important to note that the weekly control rod exercise test would be unable to detect fuel channel bow for fully withdrawn control rods because the high friction region is above notch position 46. In the case of partially inserted rods, there is a potential for the control rod exercise test to detect fuel channel bow; however, the current control rod exercise test has failed to identify the friction condition that exists in channel bow impacted cells.

For Maintenance Rule train actual unreliability, there were zero (0) unplanned inoperable control rods on either unit during the initial review period from January 1, 1998 through September 25,

2003. However, subsequent to the initial review, as of April 23, 2004, a total of 5 Unit 1 control rods have been declared inoperable based on the interim surveillance requirements specified by General Electric (GE) Nuclear Energy in 10 CFR Part 21 Notification SC03-08 (Ref. 4). This notification establishes augmented surveillance requirements for the control rod drive mechanisms that are intended to ensure that fuel bundle lift and excessive loads on reactor internals will not occur. Of the 5 Unit 1 control rods that were declared inoperable, 3 failed to successfully insert during the continuous insert stall test, requiring them to be declared inoperable. The remaining 2 control rods were declared inoperable because of degrading performance related to fuel channel bow interference. All 5 of the Unit 1 control rods were declared inoperable as a result of fuel channel bow interference and not as a result of a CRD system performance issue. For Maintenance Rule unreliability performance criteria, the number of unplanned inoperable rods is less than or equal to 4 (24-month rolling total). Unavailability is not tracked for the CRD System under the Maintenance Rule.

A review of corrective maintenance and preventative maintenance work requests for the previous five years was performed. There were a number of corrective maintenance work requests written between January 1, 1998 and September 25, 2003, to address the failure of a control rod drive to reposition when attempting to do so using the normal drive water pressure band. The inability to reposition a control rod using the normal drive water pressure band does not impact the operability of the control rod drive mechanism nor does it exceed an acceptance criteria specified in the control rod exercise test. In each case, the control rod in question was able to be successfully repositioned using elevated drive water pressure, which is directed per station procedures. These issues are due primarily to seal degradation that causes increased seal leakage, ultimately leading to drive motion problems. But in several instances the need to increase drive water pressure to reposition a control rod was attributable to fuel channel bow interference. Drives requiring increased drive water pressure to be successfully repositioned as a result of seal leakage have been and will continue to be replaced during refueling outages. For fuel channel bow affected control rods, a reactor core redesign strategy is being employed to eliminate the fuel channel bow interference that is currently being encountered.

The preventative maintenance tasks for the control rod drive mechanisms have identified an average collet/flange tube cracking rate of approximately 40%. All control rod drive mechanisms that are removed from the reactor core are nondestructively examined to detect cracks in the collet housing region of the flange tube. If cracks are identified in the collet housing region then the flange tube must be discarded. An investigation has determined that the cracking is consistent with the failure modes specified in GE Service Information Letter (SIL) No. 139 (Ref. 5). GE, the control rod drive manufacturer, does not specify any particular preventative maintenance frequency for control rod drive mechanisms. However, GE has recommended, as part of SIL No. 139, that each control rod drive mechanism be exercised weekly to detect a failure in the collet housing region of the control rod drive flange tube. A collet housing failure could result in the inability to insert, withdraw, and/or scram a control rod. TS Surveillance Requirement 4.1.3.1.2.a ensures that LGS complies with the SIL No. 139 recommendations. The proposed STI change would result in the recommendation of SIL No. 139 not being met. However, GE has evaluated the acceptability of the proposed STI change for LGS, and the results of the evaluation are documented in GE Nuclear Energy Report GE-NE-0000-0024-9858 R0 (Ref. 6). The GE evaluation concluded that extending the testing frequency from 7 days to 31 days would not compromise the material condition or reliability of the CRD system. Furthermore, the evaluation concluded that monthly control rod notch testing was adequate to detect collet housing failures given the slow collet housing crack growth rate.

The ASME Inservice Testing (IST) Program utilizes TS Surveillance Requirement 4.1.3.1.2.a to verify proper function of the cooling water check valve. The IST Program Specification does not mandate a specific frequency of control rod exercise testing to verify cooling water check valve functionality. The IST Program Specification only requires that each control rod be moved at least once per cycle to verify functionality of certain CRD System components, including the cooling water check valve. Given this information, there is no impact to the IST Program as a result of the proposed STI change. Moreover, the performance of monthly control rod exercise test will continue to exceed the minimum IST Program testing requirements.

The control rod drive mechanisms and associated components are highly reliable. The scram performance of the control rods is excellent, giving ample margin to the limits specified in TS Sections 3.1.3.2, 3.1.3.3, and 3.1.3.4. Two additional items must also be considered: (1) the Improved Standard Technical Specifications (ISTS) (NUREG-1433; Ref. 7) only requires partially inserted control rods to be exercise tested monthly, and (2) neither the ISTS nor the existing LGS TS require fully inserted control rods to be exercise tested. Plants governed by the ISTS have not reported any adverse impacts on CRD system performance as a result of monthly exercise testing of partially inserted control rods. In the case of fully inserted control rods, the exercise test could be performed as infrequently as 120 days or more. Plants, including LGS, sometimes operate with control rods fully inserted to optimize reactor operation (i.e., achieve cycle exposure goals, spectral shift considerations, maximize thermal margin, etc.) or due to extenuating circumstances (e.g., a fuel defect). LGS has observed no change in reliability or performance as a result of not exercise testing control rods on at least a monthly frequency. Therefore, the precedent set by the ISTS control rod exercise test requirements for partially inserted rods, the existing allowance for not exercise testing fully inserted rods, industry and station operating experience, and the performance of the CRD system provide grounds for changing the surveillance frequency from 7 days to 31 days for all control rods.

Defense-in-depth protection is not reduced. Other CRD surveillance tests are not impacted. If normal reactor shutdown methods, e.g., the Reactor Protection System (RPS) and CRD, fail, LGS Standby Liquid Control System (SLCS) is available and used in conjunction with the Redundant Reactivity Control System (RRCS) to accomplish shutdown.

Risk Analysis

Individual CRDs are not modeled in the LGS Level 1 PRA model. The bounding condition of all control rods failing to move is addressed in the PRA model for RPS, i.e., the mechanical portion of RPS fails. The probability of this occurrence is 2.10E-06. However, since the Anticipated Transient Without Scram (ATWS) contribution to CDF is less than 5% and the contribution to LERF is less than 4%, it is qualitatively assessed that the individual CRDs are of low risk significance. Extending the surveillance frequency from 7 days to 31 days will not affect this qualitative assessment.

External events include fire and seismic events. These events trigger a manual or automatic reactor scram. Reactor shutdown is presumed to occur in these analyses. The frequency of most external events is low. The frequency of an external event combined with an ATWS is even lower and therefore very unlikely. The seismic risk is considered negligible since other key plant equipment, such as Emergency Core Cooling System (ECCS) pumps are more susceptible to the impact of a seismic event than the reactor vessel internals.

LGS has no shutdown PRA Model. Shutdown risk analysis begins with reactor sub-critical, so this surveillance requirement has no impact on shutdown risk.

Conclusion

The CRD system at LGS is highly reliable and has demonstrated excellent equipment performance. The core average scram times to notch positions 45, 39, 25, and 05, are approximately 30% below the allowable value. In addition, the scram insertion time to notch position 05 for all control rod drive mechanisms is significantly less than the TS scram insertion time limit of 7.0 seconds. Most importantly, no control rod was unable to be repositioned as part of the weekly exercise test within the review period. The precedent set by the ISTS control rod exercise test requirements for partially inserted rods, the existing allowance for not exercise testing fully inserted rods, industry and station operating experience, and the performance of the CRD system provide grounds for changing the surveillance frequency from 7 days to 31 days for all control rods.

The impact of the proposed change on SIL No. 139 was evaluated by GE and found to be acceptable. Of greatest significance is the fact that there has never been a failure of a collet housing at LGS. A collet housing failure is not expected to occur in the future because the existing maintenance practices are adequate to ensure that cracked collet/flange tubes are removed from service prior to failure.

Therefore, the Integrated Decisionmaking Panel determined that extending the STI from 7 days to 31 days is acceptable, and phased implementation is not recommended for the control rod exercise test. The Maintenance Rule performance monitoring criteria currently tracks the number of unplanned inoperable control rods on a rolling 24 month period and train maintenance preventable functional failures (MPFFs). The existing monitoring established by the LGS Maintenance Rule is adequate for monitoring CRD performance, and additional surrogate monitoring is not required.

STI #2 – Standby Gas Treatment System (SGTS)/Reactor Enclosure Recirculation System (RERS) Flow Tests

LGS TS Surveillance Requirement 4.6.5.3.a requires that each standby gas treatment subsystem shall be demonstrated operable at least once per 31 days by initiating, from the control room, flow through the high efficiency particulate air (HEPA) filters and charcoal adsorbers and verifying that the subsystem operates with the heaters operable. In addition, LGS TS Surveillance Requirement 4.6.5.4.a requires each reactor enclosure recirculation subsystem shall be demonstrated operable at least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates properly. The basis for these monthly tests is related to the elimination of moisture in the filters and adsorbers as described in Regulatory Guide 1.52 (Ref. 8). The recommended STI change being evaluated would extend this surveillance frequency from 31 days to 92 days.

Maintenance Rule (MRule) Classification

Although the system is not quantitatively risk significant, it was assessed by the Maintenance Rule Expert Panel to be risk significant, and therefore, is classified as HSS in accordance with the Maintenance Rule. The SGTS and RERS systems are both safety-related and safety significant yielding a risk classification of RISC-1 per NEI 00-04, Rev. D, Figure 1-1. The Risk-Informed Categorization Process (Figure 2-1) would yield a HSS categorization as a worst case result. Since LGS Maintenance Rule Expert Panel has already classified this system as risk significant, compliance with NEI 00-04 is achieved.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the UFSAR, General Design Criterion (GDC) 43, LGS commitment tracking database, NRC SERs, and Regulatory Guides. The specific basis for the 31 day surveillance interval is not given in the LGS TS Bases section nor in the LGS UFSAR Sections 6.5.1 or 9.4.2 which discuss the subject systems. However, Regulatory Position C.4.d of Regulatory Guide 1.52, Revision 2, relating to maintenance requirements, recommends:

> "Each ESF [*Engineered Safety Feature*] atmosphere cleanup train should be operated at least 10 hours per month, with the heaters on (if so equipped), in order to reduce the buildup of moisture on the adsorbers and HEPA filters."

The bases for Surveillance Requirement 3.6.4.3.1 in the ISTS, which corresponds to the subject LGS TS test, also notes the need for 10 hours of operation per month for reduction of moisture buildup in the filters. The basis for the requirement of a monthly test with the heaters energized is clearly related to the desired elimination of moisture in the filters and adsorbers. LGS took exception to this "10 hour" requirement. The LGS UFSAR Table 6.5-2 states that LGS does not conform to Regulatory Guide 1.52, Position C.4.d because the Standby Gas Treatment System (SGTS) and Reactor Enclosure Recirculation System (RERS) trains are continuously purged with dry instrumentation air to prevent build-up of moisture. UFSAR Sections 6.5.1.1.2 and 6.5.1.3.2 provide additional discussion of this method of moisture control.

The surveillance test, maintenance rule, and corrective maintenance histories were all reviewed for the period between January 1, 1998 and September 30, 2003. The results of the SGTS and RERS flow test were reviewed during this period. All tests were reviewed with the focus on

those graded as either "Unsatisfactory" or "Fail." There was a total of only four failures of the Unit 1 monthly surveillance test and only one failure of the Unit 2 test in the review period. It should be noted that all of these test failures were a result of problems on the RERS system only. No failures were caused by the SGTS. The review revealed that several other tests were aborted as a result of other issues, for example, high reactor water cleanup (RWCU) system room temperatures because the normal heating, ventilation and air conditioning (HVAC) system was not in service. These test abortions were not caused by failure of the RERS or SGTS system, and are therefore not counted as "failed" tests.

Although there have been many corrective maintenance (CM) work requests written against the SGTS and RERS systems, only a small number of these issues either resulted in failure of the surveillance test or resulted in the loss of the maintenance rule system or component functionality. Additionally, the majority of these CM work requests were identified by means other than the monthly surveillance test, e.g., during rounds by Operations, during performance of the SGTS heater differential pressure test, or while placing the SGTS and RERS in service to support maintenance on the reactor enclosure HVAC system.

The performance indicators (PIs) for SGTS and RERS are MPFFs for reliability. The Maintenance Rule functional failures were reviewed for SGTS and RERS. There were only 14 functional failures on the system in the past seven years; 10 were RERS failures, five of which were discovered while performing the SGTS and RERS flow test, and four were SGTS failures, none of which were discovered while performing the SGTS and RERS flow test. A review was also performed for MPFFs on the system. There was only one MPFF which occurred on SGTS and only one MPFF which occurred on RERS in the past seven years. In the past seven years, the SGTS system reached MRule 10 CFR 50.65(a)(1) status only a single time, which was a result of Agastat relay and Love controller issues on the system.

The unavailability of the SGTS and RERS systems is currently tracked in terms of Limiting Conditions for Operation (LCO) hours which is conservative compared to train unavailability. The performance indicator measures LCO hours averaged over a 24 month period.

Unavailability Performance Criteria (limit) for SGTS : 7 %
Actual 'A' SGTS Train Unavailability: 1.62 %
Actual 'B' SGTS Train Unavailability: 2.08 %

Unavailability Performance Criteria (limit) for RERS: 4 %
Actual '1A' RERS Train Unavailability: 1.26 %
Actual '1B' RERS Train Unavailability: 0.24 %
Actual '2A' RERS Train Unavailability: 0.59 %
Actual '2B' RERS Train Unavailability: 0.75 %

A review of maintenance work requests during the same period was performed. A significant number of CM work requests were written to address Love controller failures which caused SGTS or RERS to fail. To address this a Love controller replacement project is currently being implemented to replace the existing controllers with new more reliable controllers. Another significant contributor to SGTS and RERS problems in the past five years has been the failure of Agastat relays. An Agastat relay program is currently in place which will help to improve the reliability of the system.

Regulatory Guide 1.52, Rev. 2, position C.4.d, recommends monthly operation of the ESF atmosphere cleanup systems to protect the filtration systems. Like LGS, other nuclear plants

get the benefit of detecting additional failures by running SGTS and RERS monthly. However, the detection of failures at other plants is also not limited to performance of the monthly surveillance test. Although failures were found on SGTS and RERS at various nuclear plants, only a relatively small number of these failures (i.e., heater failures) affected the moisture elimination design features. No failures were found on components associated with instrument air injection to the filters, which is possibly because few plants have this design feature.

The SGTS and RERS fans were designed for operation over a continuous or intermittent 40 year life. The vendor manuals do not specify a specific time interval for performing maintenance on either the SGTS or RERS fans.

ANSI N510 (Ref. 9) describes airflow testing but does not specify a frequency. Performance of this event driven testing is recommended after initial construction and after any major system modifications.

The instrument air supply used to reduce the buildup of moisture to the charcoal filters on SGTS and RERS has demonstrated high reliability. Safety related solenoid valves are used to provide dry instrument air to the upstream side of the charcoal adsorbers. Whenever the filter systems are not in use, the associated solenoid valve is energized to allow a continuous purge of the adsorbers. Instrument air at LGS is tested to ensure high quality on a regular basis per the requirements of ANSI/ISA S-7.3 (Ref. 10), and as specified in the site response to Generic Letter No. 88-14 dated February 13, 1989 (Ref. 11).

The currently specified test frequency results in the SGTS being run multiple times per month, introducing wear on system components which are designed to operate during an accident. This also challenges the Operations group because performance of this test is man-power intensive. Performance of this test requires shutting down the normal ventilation system. There is always a concern for elevating room temperatures and the potential of entering an emergency operating procedure when the normal HVAC system is not operating to support this surveillance test. When a high temperature condition exists, the surveillance test is aborted until normal operating temperatures are restored. This results in additional fans stops and starts. A quarterly test frequency would help to reduce the operator challenges by permitting this test to be scheduled out of the summer months.

There are two trains of SGTS shared by Unit 1 and Unit 2. There are two trains of RERS per unit. The extension of the STI, given that reliability remains the same, does not affect the defense-in-depth of the plants.

Risk Analysis

SGTS and RERS do not affect the Level 1 PRA being solely related to prevention of releases from secondary containment which is addressed in the Level 2 PRA analysis.

The potential for SGTS/RERS to provide a mechanism to reduce fission product releases in the Level 2 evaluation is accounted for in the RB (Reactor Building Effectiveness) node of the Level 2 PRA model. However, currently only passive fission product removal mechanisms (such as gravitational settling of aerosols) is credited in providing a limited amount of reactor building effectiveness in the Level 2 evaluation. This is based on the following:

1) For any large containment failure modes, the SGTS/RERS system would be incapable of preventing overpressure failure of the blowout panels in the reactor building. Thus, SGTS/RERS would be bypassed for all large containment failure mechanisms.

2) For small containment failure modes, SGTS could potentially avert overpressure and failure of the blowout panels, but given severe accident scenario conditions, closure of the SGTS/RERS dampers is likely to occur on high gas temperatures such that SGTS/RERS is also currently not credited for reducing the source term released from the reactor building in these scenarios.

Per the description provided above, SGTS and RERS as currently credited and modeled have no impact on LERF for internal events. Calculated delta LERF is zero. A delta LERF of zero is within the Regulatory Guide 1.174 (Ref. 12) limits.

The gap analysis of the LGS PRA against the ASME PRA Standard (Ref. 13) and Regulatory Guide 1.200 (Ref. 14) was reviewed and no identified issues affect this analysis.

There is no impact on CDF for fire risk for the same reason as internal events. Similarly, there is zero impact on fire LERF. The limits of Regulatory Guide 1.174 are therefore met. Fires in charcoal beds can occur during operation of the system. Thus, reducing the number of system operations would reduce the fire frequency in the area of the SGTS charcoal beds.

There is no impact on CDF for seismic risk for the same reason as internal events. Similarly, there is zero impact on seismic LERF. The limits of Regulatory Guide 1.174 are therefore met.

The SGTS system at LGS contains three zones. They are the Unit 1 reactor building, the Unit 2 reactor building and the common refuel floor. The RERS systems serve only the reactor buildings and do not interface with the refuel floor unless the SGTS refuel floor zone is cross tied to a reactor building zone. This cross tie capability is a normal design feature of SGTS.

SGTS is typically required for filtering of the primary and/or secondary containment atmosphere during refueling or maintenance outages that require opening of the reactor pressure boundary. The assessment of SGTS under shutdown conditions has many of the same attributes associated with the similar analysis performed for the at-power condition. For example, SGTS cannot prevent core damage under power or shutdown conditions. SGTS provides a part of secondary containment. Under shutdown conditions, SGTS provides a method to maintain a negative pressure inside the reactor enclosure and refuel floor. The SGTS can filter secondary containment atmosphere before release to the environment. It is capable of radionuclide filtration for events such as a fuel assembly drop accident. These accidents are not sufficient to produce a LERF whether SGTS is operating or not. Therefore, SGTS can be considered to be of low risk impact during shutdown.

Conclusion

There is no LGS TS basis for running the SGTS or RERS systems on a monthly interval. The basis for the monthly surveillance tests comes from the recommendation in Regulatory Guide 1.52, Revision 2, to operate the systems monthly to prevent moisture buildup on the filters. LGS took exception to this recommendation as discussed in LGS UFSAR Table 6.5-2. The design of the SGTS and RERS systems at LGS includes a safety related feature that injects dry instrument air upstream of the adsorbers when these systems are not operating in order to prevent build-up of moisture. Therefore, a change in the surveillance interval between tests from

monthly to quarterly will not result in moisture accumulation that would reduce the capability of the adsorbers to remove iodine from the exhaust air flow stream.

Although there have been a number of corrective maintenance activities for the SGTS and RERS systems, only a small number of these issues has resulted in a loss of the maintenance rule system function. Additionally, the majority of these corrective maintenance activities were identified by means other than the monthly surveillance test. A change in the surveillance test frequency from monthly to quarterly would be beneficial in that it would reduce the wear on system components and thereby reduce downtime associated with maintenance and repairs. Surveillance test frequency on a quarterly interval is considered adequate to verify operability, as demonstrated by the required quarterly test interval for other equipment important to safety which have a similar function, such as the requirement for quarterly verification of the isolation time of the secondary containment and refueling area isolation valves, as required by LGS TS Sections 4.6.5.2.1 and 4.6.5.2.2.

Based on the surveillance test, maintenance rule, availability history and risk, the Integrated Decisionmaking Panel determined that the surveillance interval for the SGTS and RERS flow tests may be changed directly to a quarterly (i.e., 92 day) frequency. The existing monitoring established by the LGS Maintenance Rule is adequate for monitoring the SGTS and RERS systems. Thus, LCO hours (unavailability) and MPFFs will continue to be tracked at the train level.

STI #3 – 4kV Emergency Bus Undervoltage Channel Functional Test

LGS TS Surveillance Requirement 4.3.3.1 requires that each Emergency Core Cooling System (ECCS) actuation instrumentation channel shall be demonstrated operable by the performance of the Channel Check, Channel Functional Test and Channel Calibration operations for the Operational Conditions and at the frequencies shown in Table 4.3.3.1-1. LGS TS Table 4.3.3.1-1, "Emergency Core Cooling System Actuation Instrumentation Surveillance Requirements," Item 5.b, "4.16 kV Emergency Bus Under-voltage (Degraded Voltage)," requires a Channel Functional Test at least once per month (31 days).

This surveillance test is a very specialized activity that requires extensive coordination, and has the potential to trip a bus if performed incorrectly. Therefore, performing it less frequently reduces the number of opportunities for human error. A specialized group of individuals is dedicated to performing this surveillance test because of the potential risk. Another benefit of performing this test less frequently is reducing wear and aging induced by testing.

The recommended STI change being evaluated would extend this surveillance requirement frequency from monthly (31 days) to quarterly (92 days).

Maintenance Rule (MRule) Classification

The SSC is modeled in the LGS PRA Model. The system is quantitatively risk significant. The MRule risk significance classification is HSS (high). Relative to NEI 00-04 risk significance insights, the MRule HSS classification is retained as permitted by the Initiative 5b methodology.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the UFSAR, GDC 18, "Inspection and Testing of Electric Power Systems," LGS commitment tracking database, NRC SERs, and Regulatory Guides. Neither the LGS TS nor the ISTS provide a basis for the 31 day surveillance interval. Based on this review, there are no specific commitments found that would prohibit extending this STI.

The surveillance test, maintenance rule, and corrective maintenance history were all reviewed for the period from January 1, 1998, through November 11, 2003. The results of the channel functional test for Units 1 and 2 were reviewed for this six year period. All tests were reviewed with the focus on those graded as either "Unsatisfactory" or "Fail." There were a total of four identified failures of the Unit 1 monthly surveillance test and no failures of the Unit 2 test in the six year review period. Of the four Unit 1 reported failures, one was attributed to an aborted test after the associated Emergency Diesel Generator (EDG) was not run (required for satisfactory completion of the test). The test was completed satisfactorily the next day. Of the three remaining failures, only one was an actual relay failure. The other two failures were attributed to test equipment failures. Therefore, of the four Unit 1 relays identified, only one failure was actually a relay-related failure.

There is no specific reliability tracking mechanism nor any Maintenance Rule performance criteria for reliability associated with 4 kV under voltage relays. However, protective relaying is included under the train MPFF performance criteria. If a relay failure occurs, a CM work request is normally generated that initiates a functional failure review. These relays are normally energized and normally fail-safe. The function of these relays is to detect degraded bus voltage and to automatically transfer power to the alternate bus. The Maintenance Rule functional

failures were reviewed for the 4 kV system. With respect to the degraded bus relays, there were no functional failures or MPFFs on the system during the six year review period. The specific relay failure identified above did not result in a functional failure since failure of this relay does not prevent automatic transfer for degraded conditions. This is because there is redundancy in the system through the use of three relays in parallel. Each of the three relays has different operating characteristics using over-lapping trip functions. Therefore, loss of one relay does not defeat the function of the degraded bus scheme. The 4 kV system has been a 10 CFR 50.65(a)(2) system over the last six years.

The unavailability of the 4 kV system is currently tracked in terms of bus unavailability. A train on 4 kV is defined as the divisional switchgear breakers and any associated divisional relaying that could have an adverse impact on a particular division of the 4 kV system. There were no unplanned LCO entries associated with the 4 kV system during the five year review period from 1998 through 2002.

The unavailability performance criteria (limit) for 4 kV is 0.5%. The actual train unavailability for all eight 4 kV buses (four per unit) was 0% over the six year review period. Unless a 4 kV bus is lost, unavailability is normally assigned to the individual loads off of the particular breaker.

A search of industry operating experience was performed. A limited number of events were identified with the most prominent issues being related to setpoint drift. Based on the review of operating experience, there is no evidence to suggest a specific failure trend linked to extended surveillance testing. The operating experience does suggest that setpoint drift is possible at three months or greater; however, with the large number of actual applications for these relays, the total number of setpoint drift issues is considered minimal. None of the reported events prevented performance of a safety system actuation or plant challenge.

The Performance Centered Maintenance (PCM) template for control/timing relays recommends functional testing on a two year basis. Calibration and replacement of these relays are listed "as required". Therefore, other than the two year recommended functional test, the relay calibration and replacement are application specific. The PCM template for protective relays recommends an as-found testing and calibration frequency of four years. Based on the PCM template recommendations, there is no specific recommendation to test and/or calibration these relays on a frequency less than three months.

A review of the vendor manuals for the affected relays was performed. The recommended frequency for periodic testing and maintenance of the relays was specified at either one to two years or was not specified at all. No specific drift values were identified in the vendor data. Preventative maintenance tasks associated with the 4 kV degraded relays are not affected by the performance of this test on a quarterly frequency.

There are no ASME or other codes for these under voltage relays that specify testing intervals.

The degraded bus relays are normally energized and perform an over-lapping design function to detect degraded line voltage and auto-transfer to the alternate 4 kV source. Performance of this monthly test requires application of test jacks into live circuits and carries with it the potential to trip the bus. Additionally, frequent testing, such as this, can promote accelerated wear and aging that could promote premature failure.

By virtue of the degraded bus relay circuit, one single failure of a relay does not make the associated bus inoperable. The inoperable relay is placed in bypass and then subsequently

replaced. Test data and failure history for these type relays in this application at LGS demonstrates a high reliability factor.

The number and operation of the EDG start relays is unchanged by the extension of the STI. The extension of the STI, given that reliability remains the same, does not affect the defense-in-depth of the plants. The defense-in-depth protection of the plant remains unchanged.

Risk Analysis

All relevant systems were included in the internal events quantification; thus, there are no systems not modeled that would impact the risk analysis. The subject surveillance requirement verifies the capability of the 4kv bus undervoltage relays to sense low bus voltage. This initiates, for the purposes of the PRA, a start of the EDG on that 4kV bus. The relays were included in the EDG initiation logic.

The Limerick PRA has been reviewed against the ASME PRA Standard and Regulatory Guide 1.200. The identified gaps that affect this analysis were addressed as follows:

- Explicit modeling of the EDG initiation logic (with manual backup) was added to the model for this assessment.
- An examination of Loss-of-Coolant-Accident scenarios with consequential Loss-of-Offsite-Power was also added to the model for this assessment.
- Existing modules that related to the EDG initiation logic were expanded.
- The parameter file was fully populated for performance of the parametric uncertainty assessment.
- There is very limited use of plant-specific data in the LGS PRA models. The incorporation of more plant-specific data and the incorporation of revised common cause failure probabilities are anticipated, for the most part, to reduce the failure probabilities used in the model. This means that the currently calculated impacts are most likely conservative.
- Other remaining issues from the gap analysis are considered as being bounded by the uncertainty assessment performed for this analysis.

The above changes created an application specific PRA model. This model was exercised to assess the potential increase in CDF and LERF due to the surveillance interval extension. This assessment was performed as follows:

- The standby interval for the eight affected relays (four per unit) were increased from their base value of 31 days to the extended interval of 92 days.

- Based on the standby failure rate of 5.0E-7/hr from the Electric Power Research Institute (EPRI) Advanced Light Water Reactor (ALWR) database (Ref. 15) for electromechanical relays, this changed the standby failure probability contribution from 1.86E-4 to 5.52E-4 for each of the eight relays.

- The associated common cause failure contribution for the two groups of four from each unit was increased from 3.46E-6 to 1.03E-5. The common cause failure contribution was determined for a four-component generic group from Table 5-11 of NUREG/CR-5485 (Ref.16).

With the changes described above, the best estimate change in CDF is less than 1.0E-9/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-6/yr. The change in LERF is less than 1E-11/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-7/yr. Sensitivity cases with increased failure probabilities indicate a very negligible increase in the CDF and LERF values even when 3-times (i.e., approximate 95th percentile values) the extended interval failure rates are utilized.

There is no quantitative external events (fire and seismic) or shutdown PRA available for this analysis. For fire risk, the only areas that could be affected would be those that include a loss of offsite power where the subject relays are required to function. Here, the potential change in risk would be comparable to that quantified for the internal events PRA. For seismic risk, only those earthquake magnitudes that would cause a loss of offsite power (but would not fail the EDGs) would require these relays to function. Again, the change in risk would be comparable to that calculated for the internal events PRA. For shutdown risk, the impact of failure of one of these relays would be less due to the greater response times available during shutdown and due to the need for less than the full complement of electrical support equipment. Based on the very small impact on the internal events PRA model, it is judged that the impact from fire risk, seismic risk and shutdown risk is very small though no quantitative assessments are available.

A parametric uncertainty assessment was performed on the quantitative internal events CDF and LERF calculation. This assessment indicates that the 95th percentile CDF value is about a factor of three times the base point estimate mean value, and the 95th percentile LERF value is about a factor of four times the base point estimate mean value. The low change in CDF and LERF for this assessment indicates that even at the 95th percentile values for CDF and LERF, the change in risk would be of very low risk significance. No other external events are applicable. Internal flooding is contained in the internal events PRA model.

The previous cumulative increase in CDF was zero. With this STI, the cumulative increase in CDF is < 1E-9/yr. The previous cumulative increase in LERF was zero. With this STI, the cumulative increase in LERF is < 1E-11. These cumulative values remain within the Regulatory Guide 1.174 limits.

Conclusion

There is no LGS TS basis for operating the 4 kV under voltage degraded relays on a monthly interval. Review of past test results along with corrective maintenance and functional failures demonstrates a strong record of operation for these relays. The change to the surveillance test interval is of very low risk significance from a CDF and LERF perspective as evidenced by the changes remaining within Regulatory Guide 1.174 limits.

Therefore, the Integrated Decisionmaking Panel determined that a change in the interval between tests from monthly to quarterly is acceptable. The Maintenance Rule will continue to be used as a monitoring tool to ensure that setpoint drift and/or relay failures are properly identified and evaluated upon implementation of this new frequency.

STI #4 – Loss of Coolant Accident (LOCA)/Loss of Offsite Power (LOOP) Testing

LGS TS Surveillance Requirements 4.8.1.1.2.e.2 through 7, and 9 through 13, require various tests to be performed on a 24 month frequency, including: reject largest load, reject 2850 KW load, LOOP start, ECCS start, LOCA-LOOP start, trips bypassed, auto load less than 3100 KW, synchronize to the grid while loaded, transfer loads to the grid, restore to standby, ECCS start overrides test mode, load sequence timers within 10% design interval, and lockout active only when required. LGS TS Surveillance Requirements 4.3.3.1 and Table 4.3.3.1-1, Item 5.a; 4.3.3.2; and 4.3.3.3 and Table 3.3.3-3, Items 1. and 2., require various ECCS actuation instrumentation tests to be performed on a 24 month frequency, including: the 4.16 kV emergency bus undervoltage (loss of voltage) channel functional test, ECCS logic system functional tests, and ECCS response time tests for the Core Spray system and the Low Pressure Coolant Injection mode of the Residual Heat Removal (RHR) system. LGS TS Surveillance Requirement 4.7.1.2.b.2 requires the Emergency Service Water system pump start on diesel start test to be performed on a 24 month frequency. These tests collectively are referred to as the LOCA/LOOP test.

The recommended STI change being evaluated would extend these surveillance frequencies from 24 months to 48 months or 96 months.

Extension of the LOCA/LOOP testing beyond 24 months will have several benefits. One, the required resources involved in performing a LOCA/LOOP test are extensive. Therefore, reducing the number of LOCA/LOOP tests performed during any given outage will free up resources to perform other outage tasks. Two, the coordination of equipment to support a LOCA/LOOP test impacts the ability to perform other station work. This extension will free up equipment to allow for maintenance on multiple systems that otherwise could not be performed. Three, this initiative will also minimize the number of temporary power installations that occur during an outage thereby reducing the risk of misalignments and again freeing resources both during the outage and in preparation for the outage. Four, multiple perturbations of electrical equipment can result in equipment failures or complicated re-energization processes (with respect to equipment that is de-energized when the bus is de-energized).

Maintenance Rule (MRule) Information

The SSC is modeled in the LGS PRA Model. The system is quantitatively risk significant. The MRule risk significance classification is HSS (high). Relative to NEI 00-04 risk significance insights, the MRule HSS classification is retained as permitted by the Initiative 5b methodology.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the LGS TS, the UFSAR, NRC SERs, the LGS Inservice Testing (IST) Program, LGS commitment tracking database, Regulatory Guides, and Institute of Electrical and Electronic Engineers (IEEE) standards. Based on this review, no commitments were identified that would prohibit this STI change.

A review of surveillance test history was performed for the period from January 1, 1994 through November 11, 2003. The 24-month TS surveillance requirements and UFSAR commitments associated with the LOCA/LOOP tests were performed five times during the specified review period for each unit. With four diesels per unit, this yields a total of 20 tests per unit. In addition, in 2002 and 2003, the LOCA/LOOP testing was divided into the outage test and the

on-line LOCA/Load Reject test for Unit 1 and Unit 2 respectively. This resulted in the addition of four tests per unit for the review period bringing the total number of tests for each unit to 24, or 48 total.

Out of the 48 tests performed, 18 resulted in an unsatisfactory test. From those 18 tests, nine were unsatisfactory due solely to coordination issues and not hardware failures. Of the remaining nine unsatisfactory tests, only two involved significant issues related to the failure to meet TS surveillance requirements. The first was on the D14 EDG when the voltage regulator auto raise adjustment failed to work properly following a preventive maintenance (PM) activity that was performed on the voltage regulator the day prior to the test. The second failure was on the D11 EDG when the EDG output breaker cell switch failed to completely make up due to an improperly installed bolt that was interfering with the cell switch linkage. This prevented the cell switch contacts associated with the emergency service water (ESW) pump breaker closure from making up thereby preventing the ESW pump breaker from closing within the required TS time. Both of these issues are being counted as unsatisfactory tests since they are valid failures that most likely would have only been detected by the LOCA/LOOP tests. Neither of these issues were due to time-dependent failures. Based upon the LOCA/LOOP and LOCA/Load Reject surveillance test review, the impact of extending the test frequencies is relatively minor.

The CM history review against the EDGs for the period from January 1, 1998, through October 24, 2003, resulted in quite a number corrective maintenance items, which included both the EDGs and the 4 kV system. Generally speaking, the EDG items are mostly minor maintenance type items such as minor leaks (lube oil, air, or jacket water), loose bolts or fittings, non-safety related equipment being out of tolerance (temperature indicators or panel gauges) and other various nuisance type items. These items were all reviewed for functional failures and operability where appropriate. More significant issues are discussed below.

The D14 EDG experienced a ground on the shutdown solenoid within the mechanical governor. The ground resulted from the insulation on the DC wiring being worn away by contact with a knuckle-joint. The engine was shutdown, the governor was repaired, and the engine was restarted and tested satisfactorily. Although the cause of the ground was discovered during the online LOCA/Load Reject Test, this could have occurred during any surveillance test.

The D22 EDG was found to be indicating 300 rpm with the EDG running at full speed and carrying load. Inspections determined that the signal generator had a frayed cable preventing it from outputting the proper speed signal. An evaluation was performed to determine the impact to the LOCA/LOOP response times due to the fact that the LOCA/LOOP logic may no longer be actuated off of the low or high speed relay but rather the redundant jacket water pressure switch. The evaluation showed that the EDG would have been able to meet its function. This was discovered during on-line testing. Corrective actions are in place to proactively replace all signal generators that are original equipment.

The D22 EDG blower was found during the overhaul to be outside of its impeller-to-wall clearances. There was still margin in this clearance, which would have allowed the blower to continue to operate. The cause was due to the manufacturing process.

D11 EDG experienced a generator field ground. The resulting inspections revealed that the generator field leads were the source of the ground. All generators were proactively repaired during subsequent overhauls to prevent this issue from occurring on the other EDG sets.

The D11 and D14 generator bearings have been replaced due to higher than normal vibrations. The cause was due to improper clearances between the generator shaft and bearing. This may have been aggravated by the field lead repairs performed as a result of the D11 EDG field ground event identified above.

On D24 EDG, rack oscillations were observed during a run. Tuning was unable to completely resolve the problem and as a result the frequency response during the RHR pump load reject post maintenance test (PMT) exceeded the TS criteria. During the following overhaul the fuel injection pumps were discovered to be binding causing excessive rack tension. Once replaced, the frequency issue was able to be resolved.

The D21 EDG experienced a major failure resulting from what was believed to be a lower connecting rod bearing having been installed incorrectly. Inspections were performed on the other EDGs resulting from this failure.

The one component type that can't be challenged or monitored on-line very well are the governors. Although the governors are challenged on a fast start surveillance test, the true way to test the governors is via the LOCA/LOOP and/or LOCA/Load Reject testing. It should be noted, however, that there have been no governor related issues within at least the last four years on the LGS EDGs.

As can be seen by the list above, there are quite a variety of issues that have occurred on the EDGs. In most cases, however, the issues have not prevented the EDG from performing its function. In all cases, the issues were able to be identified via either on-line maintenance or on-line testing. There have only been 12 functional failures against the EDGs since the inception of the Maintenance Rule program in 1996. Since July of 1999, there have been over 300 start demands for each unit's EDGs. Many of these start demands were also load demands. Of the load demands, most operated the EDG at full load for greater than two hours. Out of all of these start and load demands, there have been no identified valid failures.

There is no specific reliability tracking mechanism nor any Maintenance Rule performance criteria for reliability associated with 4 kV undervoltage relays. However, protective relaying is included under the train MPFF performance criteria. If a relay failure occurs, a CM work request is normally generated that initiates a functional failure review. These relays are normally energized and normally fail-safe. The function of these relays is to detect degraded bus voltage and to automatically transfer power to the alternate bus.

The Maintenance Rule functional failures were reviewed for the 4 kV system. With respect to the degraded bus relays, there were no functional failures on the system during the six year review period. A relay failure was identified that was considered a functional failure of the relay since the failure prevented the required loads from automatically loading back onto the bus. This would not have impacted the ability of the bus to sense a degraded voltage. This is because there is redundancy in the system through the use of three relays in parallel. Each of the three relays has different operating characteristics using over-lapping trip functions. Therefore, loss of one relay does not defeat the function of the degraded bus scheme. The 4 kV system has been a 10 CFR 50.65(a)(2) system over the last six years.

CM work requests written against the associated 4 kV undervoltage relays identified no relay failures other than the one identified above. Other CM work requests written against the 4 kV system were typically minor. There were some instances of certain breakers not functioning properly as well as some relays. In most cases the relays and breakers did not impact the

reliability of the bus, but rather impacted only the components downstream of the breakers. It is also important to note that there are four divisions providing a significant amount of redundancy. Therefore, failures of a single breaker or relay will not result in the plant being unable to successfully respond to a LOCA or LOOP condition.

A review was performed for any Action Requests generated against the 4 kV/EDG LOCA initiation relays and none were found. This relay is deemed reliable. This was also confirmed by the fact that the relay is a GE HFA style relay, which is generally viewed throughout the industry as being very reliable.

Unavailability under the maintenance rule is not specifically monitored for the uniquely tested components. However, the MRule unavailability performance criteria (limit) for the EDGs (i.e., train unavailability/24 months) is 2.5%. Unavailability for the individual EDGs through December 2003 is as follows:

D11 - 0.29%, D12 - 1.34%, D13 - 1.03%, D14 - 1.23%,
D21 - 1.40%, D22 - 1.30%, D23 - 0.03%, and D24 - 2.75%.

All EDGs have unavailability below the performance criteria threshold except D24. The D24 value was primarily attributed to two D24 EDG overhauls occurring within the same 24 month period based on station scheduling needs. The performance criteria is based on only one overhaul in a 24 month interval. (Note: The station Maintenance Rule Expert Panel concluded that D24 EDG train should remain classified as a 10CFR50.65(a)(2) system since most of the maintenance performed over the last two years was done to proactively improve the condition of the EDG and was not in response to degraded conditions.)

The LOCA/LOOP test exercises multiple relays used for load shed, timing, EDG start and re-sequencing functions. Some of these relays are Agastat model EGP and/or ETR series relays and are currently only exercised during LOCA/LOOP testing. Industry operating experience review for the relays identified a known contact resistance issue due to accumulation of an oxide film layer on the contacts, which develops over time.

The LGS LOCA/LOOP tests were reviewed for similar oxidation-related operating experience. Between 1993 and 1995, the LOCA/LOOP test interval was extended from 18 months to 24 months as part of a licensing change, which extended refueling outages to the same 24 month frequency. Unit 2 was the first unit to be tested under this extended frequency in 1995. During the first two divisional LOCA/LOOP tests performed during the 1995 refueling outage, the dead bus relays (Agastat type EGP) failed to properly function and the associated EDG did not start on a simulated LOOP condition. Also, a third relay was found to be degraded during an inspection performed prior to the affected division's LOOP test.

The failure analysis of the first two relays identified that the relays malfunctioned due to oxidation of the relay contacts causing a high contact resistance when the relay de-energized. The failure analysis of the third relay identified a degraded relay coil that was unrelated to the contact oxidation failure mode. The extension of the LOCA/LOOP tests may have contributed to the cause of the two relay failures due to contact oxidation. However, all three failed relays were over 10 years old at the time of their failure, which is now known to be greater than their recommended replacement frequency. Therefore, the failures may have also been related to end-of-life. To ensure that the all four divisional bus relays on both Unit 1 and Unit 2 would continue to operate in the future, a more frequent test was established to exercise the dead bus relays. Exercising the relays 'wipes' the contacts reducing contact resistance to

improve/maintain the reliability of the relays. Since the creation of the accelerated testing, there have been no related failures during the LOCA/LOOP tests.

Exelon's current guidelines for the Agastat EGP/ETR relays recommend a functional test on a two year frequency. For the Agastat EGP/ETR relays that are uniquely tested in the LOCA/LOOP test (i.e., those that do not have accelerated testing like the dead bus relays), extending the STI from 24 months to 48 months would result in a frequency of four years for exercising these relays. This would result in higher contact resistance which may affect the ability of the relays to actuate and could impact their capability to respond to a LOCA /LOOP. Further engineering reviews of LGS and industry data for Agastat relays tested at a four year interval are required to ensure that the increased STI does not compromise the ability of the plant to respond to a LOCA/LOOP. It should be noted that the LOCA/LOOP test review identified no other issues potentially related to a STI extension.

The EDG overhaul frequency has been specified by both the owners' group and the vendor to be two years. Certain maintenance items associated with the EDGs have longer frequencies and other routine inspections are recommended at shorter frequencies.

A review of the vendor manuals for the affected relays was performed. The recommended frequency for periodic testing and maintenance of the relays was specified at either one to two years or was not specified at all. No specific drift values were identified in the vendor data.

There are no ASME or other codes for the undervoltage relays that specify testing intervals.

The LGS TS bases do not provide any detail regarding the recommended frequencies associated with the LOCA/LOOP testing. It is believed that the test interval is intended to be consistent with the refuel cycle, as the most appropriate time to perform the testing is during a plant shutdown.

Based upon this review, there are no specific commitments identified to require retention of the 2-year test frequency.

The number and operation of LOCA or LOOP relays for a EDG start is unchanged by the extension of the surveillance test interval. The extension of the STI, given that reliability remains the same does not affect the defense-in-depth of the plants. The defense-in-depth protection of the plant remains unchanged.

Risk Analysis

The subject surveillance requirement verifies the capability of 4kV bus relays to sense low bus voltage or the presence of a LOCA initiation signal. This initiates, for the purposes of the PRA, a start of the EDG on the associated 4kV bus.

The Limerick PRA has been reviewed against the ASME PRA Standard and Regulatory Guide 1.200. The identified gaps that affect this analysis were addressed as follows:

- Explicit modeling of the EDG initiation logic (with manual backup) was added to the model for this assessment.
- An examination of LOCA scenarios with consequential LOOP was also added to the model for this assessment.

- Existing modules that related to the EDG initiation logic were expanded.
- The parameter file was fully populated for performance of the parametric uncertainty assessment.
- There is very limited use of plant-specific data in the LGS PRA models. The incorporation of more plant-specific data and the incorporation of revised common cause failure probabilities are anticipated, for the most part, to reduce the failure probabilities used in the model. This means that the currently calculated impacts are most likely conservative.
- Other remaining issues from the gap analysis are considered as being bounded by the uncertainty assessment performed for this analysis.

The above changes created an application specific PRA model. This model was exercised to assess the potential increase in CDF and LERF due to the surveillance interval extension. This assessment was performed as follows:

- The standby interval for the relays were increased from their base value of two years to the bounding potential extended interval of eight years. The standby interval for the affected time delay relays were also increased by the same amounts.

- Based on the standby failure rate of 5.0E-7/hr from the EPRI ALWR database for electromechanical relays, this changed the standby failure probability contribution from 4.37E-3 to 1.73E-2 for each of the four relays within each unit.

- The associated common cause failure contribution for the two groups of four from each unit was increased from 8.13E-5 to 3.22E-4. The common cause failure contribution was determined for a four-component generic group from Table 5-11 of NUREG/CR-5485.

- Based on the standby failure rate of 5.0E-6/hr from the EPRI ALWR database for time delay relays, this changed the standby failure probability contribution from 4.25E-2 to 1.56E-1 for each of the eight relays within each unit.

- The associated common cause failure contribution for the four groups of two from each unit was increased from 2.00E-3 to 7.33E-3, and was increased from 7.91E-4 to 2.90E-3 for the two groups of four from each unit. The common cause failure contribution was determined for two-component and four-component generic groups from Table 5-11 of NUREG/CR-5485.

With the changes described above, the best estimate change in CDF is less than 1.0E-9/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-6/yr. The change in LERF is less than 1E-11/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-7/yr. Sensitivity cases with increased failure probabilities indicate a non-trivial increase in the risk metrics (~2.6E-8/yr for CDF and 8.0E-11/yr for LERF) when 3-times (i.e., approximate 95th percentile values) the extended interval failure rates are utilized. This supports the extension of the interval to only four years rather than the proposed eight years because data uncertainty is coming into play for this STI.

NOTE: Based on the guidance provided in Regulatory Guide 1.177, paragraph 2.3.4, extrapolation of the failure rate's stability too far beyond the existing data is inadvisable.

Currently, all site and industry data is at the two year interval; therefore, going beyond four years is unsupported.

There is no quantitative external events (fire and seismic) or shutdown PRA available for this analysis. For fire risk, the only areas that could be affected would be those that include a loss of offsite power where the subject relays are required to function. Here, the potential change in risk would be comparable to that quantified for the internal events PRA. No fire area in the current fire hazards analysis for LGS causes a design basis LOCA; thus, there would be no impact on fire risk because the relays are not called upon to function. For seismic risk, only those earthquake magnitudes that would cause a loss of offsite power (but would not fail the EDGs) would require the LOOP relays to function. Again, the change in risk would be comparable to that calculated for the internal events PRA. Seismic events of a magnitude to induce a large LOCA would also fail the EDGs causing no impact on risk because the system is not available to be initiated and thus is independent of the test frequency. For shutdown risk, the impact of failure of one of these relays would be less due to the greater response times available during shutdown and due to the need for less than the full complement of electrical support equipment.

A parametric uncertainty assessment indicates that the 95th percentile CDF value is about a factor of three times the base point estimate mean value, and the 95th percentile LERF value is about a factor of four times the base point estimate mean value. The low change in CDF and LERF for this assessment indicates that even at the 95th percentile values for CDF and LERF, the change in risk would be of very low risk significance. No other external events are applicable. Internal flooding is contained in the internal events PRA model.

The previous cumulative increase in CDF was < 1E-9/yr. With this STI, the cumulative increase in CDF remains < 1E-9/yr. The previous cumulative increase in LERF was < 1E-11/yr. With this STI, the cumulative increase in LERF remains < 1E-11/yr. These cumulative values remain within the Regulatory Guide 1.174 limits.

Conclusion

There is no LGS TS Bases for performing the LOCA/LOOP testing at a two year frequency. Most of the applicable Regulatory Guides that established the testing methodology state that testing should simply be performed at an appropriate frequency/period/interval. Those that do specify a frequency have a frequency consistent with an established refuel cycle period (18 months or two years).

The change to the STI from two years to four years is of very low risk significance from a CDF and LERF perspective as evidenced by the changes remaining within Regulatory Guide 1.174 limits.

However, some Agastat relays are only exercised during the LOCA/LOOP test and current operating experience does not support a longer interval for exercising these relays. Therefore, the Integrated Decisionmaking Panel does not recommend extending the interval at this time. This decision may change in the future based on the development of alternative strategies for testing the affected relays, or evaluation of additional industry failure rate data on the affected relays as it becomes available.

STI #5 – Main Steam Isolation Valve (MSIV) Closure Reactor Protection System (RPS) Channel Functional Test

LGS TS Surveillance Requirement 4.3.1.1 requires that each RPS instrumentation channel shall be demonstrated operable by the performance of Channel Check, Channel Functional Test and Channel Calibration operations for the Operational Conditions and at the frequencies shown in Table 4.3.1.1-1. LGS TS Table 4.3.1.1-1, "Reactor Protection System Instrumentation Surveillance Requirements," Item 5, "Main Steam Line Isolation Valve – Closure," requires a Channel Functional Test at least once every quarter (92 days).

The MSIV closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIV closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

The MSIV position scram is not credited in the design basis reactor pressure vessel (RPV) overpressure analysis, nor is it required for mitigation of limiting design basis events analyzed in the reload licensing analysis.

Extending this STI would reduce the length of on-line load drops, and would reduce the potential for inadvertent MSIV closures.

The recommended STI change being evaluated would extend this surveillance requirement frequency from quarterly (92 days) to 24 months.

NOTE: This example originally included extending the Channel Functional Test from quarterly to 24 months for LGS TS Table 4.3.1.1-1, Item 9, "Turbine Stop Valve – Closure," and Item 10, "Turbine Control Valve Fast Closure, Trip Oil Pressure – Low," as well; however, the commitment review for these two specific surveillance requirements revealed that the current STIs were credited as part of the main turbine missile analysis. Further review and evaluation concluded that revising the main turbine missile analysis to support extending these two STIs was not practical at this time. Therefore, the turbine stop valve closure and turbine control valve fast closure STIs were excluded from further consideration.

Maintenance Rule (MRule) Classification

The SSC is explicitly modeled in the LGS PRA Model. The system is quantitatively risk significant. The SSC was assessed by the Maintenance Rule Expert Panel to be risk significant. Therefore, the MRule risk significance classification is HSS (high). Relative to NEI 00-04 risk significance insights, the MRule HSS classification is retained as permitted by the Initiative 5b methodology.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the LGS TS Bases, the UFSAR, NRC SERs, the LGS Pump & Valve IST Program, LGS commitment tracking database, and Regulatory Guides. Based on this review, no commitments were identified that would prohibit this STI change.

The RPS/MSIV surveillance test history was reviewed for the period from January 1, 1998, through February 12, 2004. On May 21, 1996, during quarterly MSIV-RPS testing on LGS Unit 1, a reactor scram occurred. The scram was initiated by high reactor pressure. There was a failure of the RPS logic to initiate the "MSIV Not Fully Open" scram signal, although no specific failed components were found. In a history of over 800 LGS tests, no other occurrences of failure of the MSIV-RPS input were identified.

A review of the Maintenance Rule functional failures was performed for the MSIVs. One functional failure was identified, but it was due to a failed outboard DC solenoid. Since it involved an unplanned load drop greater than 20%, it was determined to be a functional failure. There have been no MPFFs on the MSIVs since Maintenance Rule monitoring has been in effect (July 1996).

A review of Maintenance Rule functional failures was also performed for RPS. One functional failure was identified, but it was due to failure of a switch to actuate. There have been no MPFFs on RPS since Maintenance Rule monitoring has been in effect (July 1996).

A review of maintenance history for the MSIV-RPS limit switches was performed for the period from January 1, 1998, through December 1, 2003. CM activities performed on the limit switches involved either wiring issues, or occurrences where the RPS limit switch did not reset following testing. The limit switch reset problem was resolved with a design change to the limit switch roller size implemented in 1995. No similar failures have occurred since the design change was implemented.

No unavailability PIs exist for MSIVs. RPS train unavailability PIs apply to the entire RPS train, not a single RPS input such as MSIV Closure.

A review of industry operating experience identified several issues related to MSIV-RPS limit switches being out of adjustment. However, the LGS calibration history has shown very good repeatability.

Full stroke exercising of the MSIVs during normal power operation requires isolating one of the four main steam lines. Isolation of a main steam line results in reactor power fluctuations, primary system pressure spikes, and increased flow in the non-isolated steam lines. This unstable operating condition could lead to a reactor scram or increase the chances of main steam relief valve actuation. Therefore, LGS performs partial stroke testing of the MSIVs. Section 4.2.4 of NUREG-1482 (Ref. 18) discourages MSIV testing at power, including partial stroke testing. This change in frequency of partial stroke testing the MSIVs will bring LGS into closer agreement with the precepts of NUREG-1482.

ISTS include a functional test of the MSIV-RPS feature on a 92 day frequency. There is no discussion with regard to the basis of the frequency.

Additional considerations: as a prerequisite to the current 92-day surveillance test, reactor power must be reduced to below 95%. The purpose of this power reduction is to limit the plant impact in the event of an inadvertent MSIV closure.

The operation of the RPS relays for MSIV closure is unchanged by the extension of the STI. The diversity of scram inputs also remains unchanged. The extension of the STI, given that reliability remains the same does not affect the defense-in-depth of the plants. The defense-in-depth protection of the plant remains unchanged.

Risk Analysis

All relevant systems were included in the internal events quantification; thus, there are no systems not modeled that would impact the risk analysis. The subject surveillance requirement verifies the capability of RPS to initiate a scram on MSIV closure.

The LGS PRA has been reviewed against the ASME PRA Standard and Regulatory Guide 1.200. The identified gaps that affect this analysis were addressed as follows:

- Existing modules that related to the RPS logic were expanded.
- The parameter file was fully populated for performance of the parametric uncertainty assessment.
- There is very limited use of plant-specific data in the LGS PRA models. The incorporation of more plant-specific data and the incorporation of revised common cause failure probabilities are anticipated, for the most part, to reduce the failure probabilities used in the model. This means that the currently calculated impacts are most likely conservative.
- Other remaining issues from the gap analysis are considered as being bounded by the uncertainty assessment performed for this analysis.

The above changes created an application specific PRA model. This model was exercised to assess the potential increase in CDF and LERF due to the surveillance interval extension. This assessment was performed as follows:

- The standby interval for the eight position switches and eight affected relays were increased from their base value of 92 days to the bounding potential interval of 2 years.

- A standby failure rate of 3.3E-7/hr from the EPRI ALWR database for level switches was used as a surrogate for the position switches. The extended interval changed the standby failure probability contribution from 3.64E-4 to 2.89E-3 for each of the eight position switches.

- The associated common cause failure contribution for the four groups of two was increased from 1.71E-5 to 1.36E-4, and was increased from 6.77E-6 to 5.38E-5 for the two groups of four. The common cause failure contribution was determined for two-component and four-component generic groups from Table 5-11 of NUREG/CR-5485.

- Based on the standby failure rate of 5.0E-7/hr from the EPRI ALWR database for electromechanical relays, this changed the standby failure probability contribution from 5.52E-4 to 4.37E-3 for each of the eight relays.

- The associated common cause failure contribution for the global failure of the relays was increased from 1.03 E-5 to 8.13E-5. The common cause failure contribution was approximated from a four-component generic group from Table 5-11 of NUREG/CR-5485.

With the changes described above, the best estimate change in CDF is less than 1.0E-9/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-6/yr. The change in LERF is less than 1E-11/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-7/yr. Sensitivity cases with increased failure probabilities indicate a very negligible increase in the CDF and LERF values even when 3-times (i.e., approximate 95th percentile values) the extended interval failure rates are utilized.

There is no quantitative external events (fire and seismic) or shutdown PRA available for this analysis. For fire risk, the fire areas that would cause an MSIV closure plant scram remain unchanged and given that component reliability is maintained the fire risk is unchanged. For seismic risk, the RPS input would generally be related to a loss of offsite power, not MSIV closure; therefore, seismic risk is unaffected. For shutdown risk, the reactor is subcritical and RPS is not required to shutdown the reactor so there is no impact on shutdown risk. The MSIVs are also generally closed during most shutdown plant operating states and the RPS input for closure of the MSIVs is irrelevant. Based on the very small impact on the internal events PRA model, it is judged that the impact from fire risk and seismic risk is very small though no quantitative assessment is available.

A parametric uncertainty assessment was performed on the quantitative internal events CDF and LERF calculation. This assessment indicates that the 95th percentile CDF value is about a factor of three times the base point estimate mean value, and the 95th percentile LERF value is about a factor of four times the base point estimate mean value. The low change in CDF and LERF for this assessment indicates that even at the 95th percentile values for CDF and LERF, the change in risk would be of very low risk significance. No other external events are applicable. Internal flooding is contained in the internal events PRA model.

The previous cumulative increase in CDF per unit was < 1E-9/yr. With this STI, the cumulative increase in CDF remains < 1E-9/yr. The previous cumulative increase in LERF was < 1E-11/yr. With this STI, the cumulative increase in LERF remains < 1E-11. These cumulative values remain within the Regulatory Guide 1.174 limits.

Conclusion

Based on the need for reactivity manipulations to perform this test and the excellent recent performance of the MSIV-RPS limit switches, revision of this TS surveillance interval is warranted.

The change to the STI is of very low risk significance from a CDF and LERF perspective as evidenced by the changes remaining within Regulatory Guide 1.174 limits.

NOTE: During the Integrated Decisionmaking Panel review of this proposed STI extension, the degree of extension of the interval from 92 days to 24 months was discussed relative to the need to avoid extrapolating standby failure rates too far beyond available data. As a result, the Integrated Decisionmaking Panel determined that a phased implementation, starting at 184 days (semiannual), would be appropriate to gain assurance that performance and associated failure rates would remain acceptable. In addition, the Integrated Decisionmaking Panel determined that monitoring of performance under the new STI was not sufficiently captured by maintenance rule performance criteria. Additional monitoring criteria for functional test performance was chosen by the Panel.

STI #6 – Redundant Reactivity Control System (RRCS) Logic System Functional Test

LGS TS Surveillance Requirement 4.3.4.1.2 requires that logic system functional (LSF) tests and simulated automatic operations of all channels shall be performed at least once per 24 months. The intent of the LSF test is to ensure that the system will provide the required recirculation pump trip (RPT) in the event of an ATWS. The benefit of extending this STI is related to outage coordination (time) and cost savings. The RRCS LSF test is manpower intensive and requires approximately 150 man-hours of station resources each outage.

The recommended STI change being evaluated would extend this surveillance frequency from 24 months to 48 months.

Maintenance Rule (MRule) Classification

The SSC is modeled in the LGS PRA Model. The SSC is not quantitatively risk significant. The SSC was assessed by the Maintenance Rule Expert Panel to be not risk significant. If the system is lost, all of its functions can be performed manually. Therefore, the MRule risk significance classification is LSS (low).

NOTE: Relative to NEI 00-04 risk significance insights, the MRule LSS classification was not re-validated using NEI 00-04. This is a deviation from the Initiative 5b methodology. Instead, since RRCS is modeled in the LGS PRA, a quantitative assessment similar to that performed for HSS systems was performed. However, the RRCS LSF SSCs remain classified as LSS.

System Performance History and Commitments

The following information was reviewed to determine if any commitments were affected by the proposed STI change: the LGS TS Bases, the Technical Requirements Manual (TRM), the UFSAR, NRC SERs, the LGS IST Program, LGS commitment tracking database, Regulatory Guides, IEEE standards, and Licensing Topical Reports. TS Bases Section 3/4.3.4 cites GE Nuclear Energy Report GENE-770-06-1 (Ref. 19) as the basis for the specified surveillance interval. GENE-770-06-1 discusses changing the test interval for the calibration/functional test from 31 days to 92 days; however, there is no mention of the 24 month LSF test. The LGS TS do not discuss the basis behind the testing interval. ISTS state that the testing interval is based on operating experience and outage scheduling. Based on this review, no commitments were identified that would prohibit this STI change.

A review of the LGS LSF test history was performed for the period from January 1, 1984, through December 18, 2003. There have been three LSF surveillance test failures in the past twenty years at LGS. None of the test failures represent an inability to provide the TS required RPT function. The first test was declared unsatisfactory due to the application of a clearance which prevented the feedwater motor gear units from running back to their minimum speed position. The surveillance test was completed satisfactorily later that day. The second test was performed as part of a PMT for corrective actions following inadvertent actuation of a standby liquid control system (SLCS) squib valve. The actuation was due to electromagnetic interference with the operation of a safety relief valve. The failed test was a partial surveillance test performed to satisfy a PMT that was planned specifically to test a SLCS relay. The relay caused an inadvertent SLCS injection. The last test required a recalibration when a SLCS storage tank low level alarm did not actuate as expected.

In addition to the 24 month LSF, there are 24 month calibration and three month functional surveillance tests performed on the RRCS system. Although this evaluation is not seeking to change the testing interval for these tests, their performance presents an opportunity to identify failures, and therefore, their histories were reviewed for trends. For the calibration tests, only two failures due to equipment "out-of-tolerance" issues were found. For the quarterly functional tests, two test failures were due to test equipment issues and two were due to equipment "out-of-tolerance" issues.

The RRCS has a self-test feature. Each time a self-test fails, an alarm is received in the main control room and an Action Request (AR) is generated. If the self-test error can be reset/cleared, no further troubleshooting or repair is required and the AR is closed. Although there were many ARs written against components in the RRCS, only nine ARs were identified in which the error could not be cleared and further investigation was required. In all nine cases, a circuit card was replaced. The self-test remains a highly reliable method of detecting equipment failures.

Each outage, Instrumentation and Controls (I&C) technicians inspect all of the RRCS circuit cards for corrosion, optical isolator crystallization, and diode condition. Performing this PM procedure has caught and corrected many issues that may have resulted in online failures. The circuit card examination PM activity is a GE recommendation. The PM scope and interval will not be affected by this STI change.

The maintenance history for the recirculation pump trip (RPT) breakers and the associated trip/close logic was also reviewed for the period from January 1, 1998, through December 23, 2003. No failures that would preclude this STI change could be found.

Unavailability is not tracked for RRCS because it is not classified as HSS.

LGS and industry operating experience review for Agastat EGP relays identified a known contact resistance issue due to accumulation of an oxide film layer on the contacts. Exercising the relays 'wipes' the contacts thereby reducing contact resistance to improve/maintain the reliability of the relays. The LSF test is currently being used to exercise the relays. If the STI is extended, alternate means of exercising the relays will need to be developed to maintain relay performance.

There are no codes or standards associated with the logic system functional test.

The operation of RRCS is unchanged by the extension of the STI. The ATWS mitigation function remains unchanged. The extension of the STI, given that reliability remains the same, does not affect the defense-in-depth of the plant. The defense-in-depth protection of the plant remains unchanged because RRCS acts as a diverse backup to RPS to shutdown the plant in the event of a plant transient.

Risk Analysis

All relevant systems were included in the internal events quantification; thus, there are no systems not modeled that would impact the risk analysis. The subject surveillance requirement verifies the capability of RRCS to initiate actions to shutdown or reduce power in the reactor in the event of the failure of RPS to initiate a scram. This is modeled in the LGS PRA; specifically, initiation of SLCS, Feedwater runback, Alternate Rod Insertion and RPT.

The LGS PRA has been reviewed against the ASME PRA Standard and Regulatory Guide 1.200. The identified gaps that affect this analysis were addressed as follows:

- Existing modules that related to the RRCS logic were expanded.
- The parameter file was fully populated for performance of the parametric uncertainty assessment.
- There is very limited use of plant-specific data in the LGS PRA models. The incorporation of more plant-specific data and the incorporation of revised common cause failure probabilities are anticipated, for the most part, to reduce the failure probabilities used in the model. This means that the currently calculated impacts are most likely conservative.
- Other remaining issues from the gap analysis are considered as being bounded by the uncertainty assessment performed for this analysis.

The above changes created an application specific PRA model. This model was exercised to assess the potential increase in CDF and LERF due to the surveillance interval extension. This assessment was performed as follows:

- The standby interval for the four RRCS modules were increased from their base value of two years to the extended interval of four years.

- A standby failure rate of 4.0E-7/hr was used as a surrogate for the trip modules. This was estimated by using 1.0E-7/hr for relays from the EPRI ALWR database and accounting for the approximate four separate components within the RRCS trip module. The extended interval changed the standby failure probability contribution from 3.50E-3 to 6.98E-3 for each of the four RRCS modules.

- The associated common cause failure contribution for the two groups of two was increased from 1.65E-4 to 3.28E-4, and was increased from 6.51E-5 to 1.30E-4 for the group of four. The common cause failure contribution was determined for two-component and four-component generic groups from Table 5-11 of NUREG/CR-5485.

With the changes described above, the best estimate change in CDF is approximately 2.0E-9/yr when extending the RRCS test interval from once per fuel cycle to once per two fuel cycles. This is much less than the Regulatory Guide 1.174 limit of 1.0E-6/yr. The change in LERF is less than 1E-11/yr. This is much less than the Regulatory Guide 1.174 limit of 1.0E-7/yr. Sensitivity cases with increased failure probabilities indicate only a slight increase in the CDF and LERF values even when 3-times (i.e., approximate 95th percentile values) the extended interval failure rates are utilized.

There is no quantitative external events (fire and seismic) or shutdown PRA available for this analysis. For fire risk, the failure of the plant to scram (RPS failure) is not considered. RRCS is thus not required because its function is a backup to RPS. Fire risk is therefore unaffected. For seismic risk, failure of the plant to scram (RPS failure) is not considered. RRCS is thus not required for seismic risk because its function is a backup to RPS. Seismic risk is therefore unaffected. For shutdown risk, the reactor is subcritical and RRCS is not required to shutdown the reactor so there is no impact on shutdown risk.

A parametric uncertainty assessment was performed on the quantitative internal events CDF and LERF calculation. This assessment indicates that the 95th percentile CDF value is about a factor of three times the base point estimate mean value, and the 95th percentile LERF value is about a factor of four times the base point estimate mean value. The low change in CDF and LERF for this assessment indicates that even at the 95th percentile values for CDF and LERF, the change in risk would be of low risk significance. No other external events are applicable. Internal flooding is contained in the internal events PRA model.

The previous cumulative increase in CDF was < 1E-9/yr. With this STI, the cumulative increase in CDF becomes approximately 2E-9/yr. The previous cumulative increase in LERF was < 1E-11/yr. With this STI, the cumulative increase in LERF becomes approximately 1E-11. These cumulative values remain within the Regulatory Guide 1.174 limits.

Conclusion

The performance history for the LSF test, the channel calibration test, and quarterly channel functional test has been excellent. This is supported by the low incidence of failures both at the station level and within the industry. The self-test feature and the circuit card inspections have proven to be the primary method of detecting and avoiding equipment failures. There are no commitments precluding a change in test frequency. The change to the STI is of very low risk significance from a CDF and LERF perspective as evidenced by the changes remaining within Regulatory Guide 1.174 limits.

Based on the above information, the Integrated Decisionmaking Panel determined that a change in LSF test frequency from 24 months to 48 months is acceptable. Note, however, that extension of this STI is contingent upon alternate means of exercising the Agastat relays to maintain relay performance. The current preventive maintenance practices (surveillance tests and circuit card inspections) along with the system self-test feature remain the most reliable methods of monitoring the system's performance. No additional monitoring is necessary.

References

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4. Letter from J. S. Post (GE Nuclear Energy) to USNRC, "Interim Surveillance Program for Fuel Channel Bow Monitoring," MFN 03-030, Rev. 1, dated April 30, 2003, forwarded Safety Information Communication (10 CFR Part 21 Communication) SC03-08, "Interim Surveillance Program for Fuel Channel Bow Monitoring," Rev. 1, dated April 30, 2003.

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7. NUREG-1433, " Standard Technical Specifications General Electric Plants, BWR/4"

8. Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," March 1978.

9. ANSI N510-1989, "Testing of Nuclear Air Treatment Systems," December 15, 1989; (Errata, January 1991).

10. ANSI/ISA S-7.3, "Quality Standard for Instrument Air," January 1, 1975 (R 1981)

11. Letter from J. W. Gallagher, Philadelphia Electric Company (*now Exelon*), to USNRC, "Response to Generic Letter No. 88-14, 'Instrument Air Supply System Problems Affecting Safety-Related Equipment'," dated February 13, 1989.

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13. American Society of Mechanical Engineers, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME RA-S-2002, dated April 2002, and Addenda in ASME RA-Sa-2033, dated December 2003.

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15. Electric Power Research Institute, "ALWR Requirements Document," TR-016780, Revision 6, Annex A ("Reliability Database for ALWR PRAs"), 1997.

16. Mosleh, A., et al., "Guidelines on Modeling Common-Cause Failures in Probabilistic Risk Assessments," NUREG/CR-5485, November 1998.

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19. GE Nuclear Energy Report GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications"

ATTACHMENT 5

LICENSE AMENDMENT REQUEST

LIMERICK GENERATING STATION, UNITS 1 AND 2
DOCKET NOS. 50-352 AND 50-353

RELOCATION OF SURVEILLANCE TEST INTERVALS FROM THE TECHNICAL SPECIFICATIONS TO A LICENSEE-CONTROLLED PROGRAM

REGULATORY GUIDE 1.200 PRA ADEQUACY EVALUATION

REGULATORY GUIDE 1.200 PRA ADEQUACY EVALUATION

Introduction

A description of the Limerick Generating Station (LGS) Probabilistic Risk Assessment (PRA) model technical adequacy to support the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b pilot application by LGS is provided in this attachment. The following items are included:

- An overview of the LGS PRA model
- An overview of the key review processes
- A discussion of the technical adequacy of the LGS PRA model consistent with the requirements of Regulatory Guide 1.200, Section 4.2 (Ref. 1)

LGS PRA Model Overview

The 2001 update to the LGS PRA model is the most recent evaluation of the risk profile at LGS for internal event challenges. There have been a series of probabilistic evaluations beginning with the original LGS PRA, followed by the Individual Plant Examination (IPE) issued in 1992 as requested by the NRC in Generic Letter 88-20 (Ref. 2), and subsequent updates to that model. These probabilistic evaluations can be summarized as follows:

Model	Date	CDF (Per Yr)
LGS PRA	1983	1.5E-05 / yr
LGS89	1989	8.5E-06 / yr
IPE	1992	4.3E-06 / yr
LGS93	1993	5.3E-06 / yr
LGS195 / LGS295	1995	4.4E-06 / yr (Unit 1)
		4.4E-06 / yr (Unit 2)
LGS197 / LGS297	1998	3.2E-06 / yr (Unit 1)
		3.2E-06 / yr (Unit 2)
LGS101 / LGS201	2002	4.5E-06 / yr (Unit 1)
		4.5E-06 / yr (Unit 2)

The LGS PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the LGS PRA is based on the event tree/fault tree methodology, which is a well-known methodology in the industry.

Additional changes have been made to the model to support the various surveillance test interval (STI) assessments. These have not significantly changed the core damage profile, but include the following enhancements:

- Incorporated supplementary accident sequence development to quantify the risk associated with Loss of Coolant Accident (LOCA) events combined with a consequential Loss of Offsite Power (LOOP), i.e., LOCA-LOOP.

- Incorporated detailed logic model development for the emergency diesel generator (EDG) automatic initiation logic, and incorporated a Human Error Probability (HEP) analysis for manual start of the EDGs following automatic initiation failure.

- Incorporated supplementary fault tree modeling (i.e., standby failures) for the Redundant Reactivity Control System (RRCS) logic and the Reactor Protection System (RPS) Main Steam Isolation Valve (MSIV) position switches.

Overview of Key Review Processes

The LGS internal events PRA received a formal industry PRA peer review in November 1998. The purpose of the PRA peer review process is to provide a method for establishing the technical quality of a PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used. The PRA peer review process uses a team composed of PRA and system analysts, each with significant expertise in both PRA development and PRA applications. This team provides both an objective review of the PRA technical elements and a subjective assessment, based on their PRA experience, regarding the acceptability of the PRA elements. The team uses a set of checklists as a framework within which to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA products available.

The peer review process for LGS resulted in 197 Fact & Observations (F&Os). There was one 'A', 59 'B', 97 'C', and 19 'D' level F&O findings identified during the review. Additionally, there were 21 'S' findings denoting a strength or superior modeling process. The large majority of the findings and observations from these assessments that the review team indicated were important (i.e., 'A' or 'B') were addressed as part of the 2001 PRA model update process. Currently, there are no 'A' and only two remaining 'B' F&O items to be addressed or dispositioned. These items were reviewed to assess their impact on this application as described later.

More recently, the LGS PRA model was evaluated to identify those ASME PRA Standard (Ref. 3) Supporting Requirements (ASME SRs) that could be enhanced to meet the intent of the requirement as stated in the ASME PRA Standard or the NRC's positions on those standards as identified in NRC Regulatory Guide 1.200. This evaluation is referred to as the Gap Analysis of the LGS PRA. The results of that evaluation indicated 84 action items that could result in improvements to meet Capability Category II of the ASME PRA Standard.

As part of this application, these 84 items were reviewed to evaluate their potential impact on the STI assessments as is also described later.

LGS PRA Model Technical Adequacy

The technical adequacy of the PRA for this Initiative 5b pilot application is based on Capability Category II of the ASME PRA Standard for all ASME SRs as being inherently sufficient to meet adequacy requirements for most risk-informed applications including risk-informed STI applications. In cases where the Gap Analysis of the LGS PRA has identified supporting requirements as less than Capability Category II, then technical adequacy for the application is deemed sufficient when the basis of the reduced capability category determination, can be shown to have little or no impact on the calculated results and the decision-making relative to the application. The impact assessment is addressed by one or more of the following techniques: 1) model change, 2) sensitivity calculations, or 3) bounding risk-informed arguments.

Consistent with the requirements of Regulatory Guide 1.200, Section 4.2, the technical adequacy of the LGS PRA model used as the basis for risk-informed applications is established by the following:

- Treatment of permanent plant changes that affect the PRA but are not yet incorporated into the PRA model,
- Documentation of the consistency with the PRA Standard as identified in the Gap Analysis,
- Identification of key assumptions and approximations, and the peer review of these assumptions, and
- A discussion of the resolution of the PRA peer review comments that are applicable to the parts of the PRA required for the application.

In addition to the Regulatory Guide 1.200 requests, the sensitivity study evaluations developed in support of assessing the application assessment are also summarized.

Plant Changes Since the Last PRA Update

The LGS PRA model and documentation has been maintained on a regular basis. To facilitate the process, an Updating Requirement Evaluation (URE) database of open items is maintained. This database was reviewed to determine the plant changes that affect the PRA but are not yet incorporated into the PRA model, and to assess their impact on this Initiative 5b pilot application. Table 1 summarizes the results of that investigation. In summary, the changes either do not affect the PRA or would not alter the assessment of the revised STIs.

Table 1
IMPACT OF PLANT CHANGES SINCE THE LAST UPDATE ON THE LIMERICK PRA MODEL

URE Number	Plant change	Impact on the LGS PRA
2004-001	Replacement of Diesel ventilation controllers with different type controller	No impact. The replacement equipment has the same function as the old equipment.
2003-020	Incorporate ARC-MCR-002 E-4,5 actions into spray pond HVAC model. This Alarm Response Card (ARC) provides operator action in response to loss of ventilation at the Spray pond pumphouse (SPPH).	Conservative. Credit for manual backup will reduce the CDF contributions from spray pond HVAC failures. Additionally, none of the specific STIs evaluated directly involve the spray pond HVAC system so there is no impact on the application.
2003-014	Replacement of SGTS controllers with different type controller	No impact. The level 2 PRA model does not go to this level of detail.
2003-015 and 2003-016	Upgrade of feedwater turbine governor	Minimal impact on risk metrics. Additionally, none of the specific STIs evaluated involve the feedwater system so there is no impact on the application.
2003-002	Need for flow through RHR heat exchanger and bypass valves for full flow of LPCI	Minimal impact on risk metrics. Additionally, none of the specific STIs evaluated involve RHR or LPCI so there is no impact on the application.
2002-050	Remove 1 of 2 position indications from shutdown cooling testable check valves	Since there is still position indication for the valves, there is no impact on any RHR HRA calculation.
2002-048	Replace unit 2 main turbine bearing wear detector with proximity based system.	Main turbine is included only as a contributor to the turbine trip initiator frequency. The only impact would be potential small future reduction in the turbine trip initiator frequency and this will be captured in routine updates of initiating event frequencies.
2002-045	Installation of digital feedwater controls in unit 1	None of the specific STIs evaluated involve the feedwater system directly, so there is no impact on the application. Expectation is that overall FW reliability will increase.
2002-044	Removal of PV-C-007-152 and 153 from the plant	Conservative. Model shows failure that is no longer present. No impact because events for these components are truncated in the level 1 model quantification.
2002-042	SV-059-128A,B replaced with ball valve, was solenoid valve	Non-solenoid valve generically has higher failure rate than previous solenoid valve. However due to system redundancy there is no impact on CDF.
2003-036	LPCI injection valve must close for DHR modes of RHR	Minimal impact on risk metrics. None of the specific STIs evaluated involve RHR or LPCI so there is no impact on the application.
2002-033	RCIC is now inhibited with remainder of injection systems in power level control procedure in ATWS	No impact. Model already does not credit RCIC for injection during power-level control in an ATWS event.

Table 1
IMPACT OF PLANT CHANGES SINCE THE LAST UPDATE ON THE LIMERICK PRA MODEL

URE Number	Plant change	Impact on the LGS PRA
2002-032	IF RHRSW is using ESW header only one of the two RHRSW pumps may be used.	Success is one RHRSW pump per loop so this is not an issue.
2002-031	Water hammer may occur on loss of power in RHR if operating in Suppression Pool Cooling at time of power loss.	None of the specific STIs evaluated involve RHR or LPCI so there is minimal impact on the application. This issue was also assessed as a Gap Analysis finding.
2002-027	Maximum normal drywell temperature raised from 135 to 145 F	Minor impact in timing assumptions related to drywell heatup.
2002-022	Suppression pool spray initiation pressure changed from 6.5 to 7.5 psig	Below level of discrimination of the model.
2002-008	Flow balance concern if ESW aligned to cooling tower	Cooling tower as source for ESW is not covered by Technical Specifications. Will have little or no impact on application results as bounding assessment shows less than 10% increase in CDF with no credit for ESW aligned to cooling tower.
2001-003	HPCI steam trap replaced with flow orifice	Minimal impact on risk metrics. Secondary failure not in primary flow path of system. Will have little or no impact on application results.
2001-002	SPPH fan actuation logic revised for lead fan manual start and lag fan temperature based start.	Model does not include level of detail of SPPH start logic, therefore no impact.

Documentation of Consistency with the PRA Standard

As part of this Initiative 5b pilot application, the 84 items identified as part of the Gap Analysis for LGS were reviewed to evaluate their potential impact on the STI assessments. Table 2 summarizes those items that have a potential impact on this application. In summary, there were a few items that were (and will be) addressed to support the specific assessment, and there were nine items identified as potentially affecting this application. These items were subject to sensitivity study evaluations as described later.

Table 2
IMPACT OF GAP ANALYSIS FINDINGS ON THE INITIATIVE 5B PILOT APPLICATION

Gap #	Description	Applicable ASME SRs	Impact on 5B Application
2	Recovery actions are explicitly modeled in the LGS PRA event trees for SW, TECW, and Instrument Air (IA). Currently, all values are 0.25. The bases for such recoveries should be better established. Other Exelon models limit such recoveries to aligning standby equipment (and do not include repair activities) and are only credited for proceduralized actions.	IE-C1, IE-C9, HR-G1, HR-H2	Potential impact on risk metrics. Investigate with sensitivity study.
6	Update the Loss of SW and Loss of TECW Initiating Event Fault Trees to use the repair time for the additional component failure values (independent and common cause failures). Similar bases should also be provided and used for the subsequent CCF values used in the Loss of AC and Loss of DC bus event trees.	IE-C8	Potential impact on risk metrics. Investigate with sensitivity study.
8	Create one HRA notebook that compiles all HEP evaluations in one place, and uses the methodology utilized in the last PRA model update for all significant HEP values.	AS-C3, HR-E2, HR-F2, HR-I1	Potential impact on risk metrics. Investigate with sensitivity study. This was combined with #33.
17	Complete LGS URE 1999-182 to eliminate all modules in the LGS PRA model.	SY-A7, SY-A10, QU-B9	Expand modules as required for the surveillance test interval assessments.
20	Revisit CCF pairs for ESW and EDG, add Circuit Breaker CCF groups, and document overall selection method. CCF values also need to be re-derived based on updated plant-specific data.	SY-B3	Potential impact on risk metrics. Investigate with sensitivity study.
21	Add initiation logic to EDG and ESW modeling. This is being partially performed in the Initiative 5b pilot project and should be added to the PRA model permanently.	SY-B11	DG initiation logic was added to support the related surveillance test interval extension assessments.

Table 2
IMPACT OF GAP ANALYSIS FINDINGS ON THE INITIATIVE 5B PILOT APPLICATION

Gap #	Description	Applicable ASME SRs	Impact on 5B Application
33	Establish the 'significant' pre-initiator HFEs based on the Regulatory Guide 1.200 definition, and re-quantify the balance of the significant HFEs using the methodologies outlined in the last PRA model update.	HR-D2	Potential impact on risk metrics. Investigate with sensitivity study.
39	Upgrade any 'significant' post-initiator HFE quantifications using the last PRA model update methodology.	HR-F2	Potential impact on risk metrics. Investigate with sensitivity study.
43	Justify the lower bounds of Joint HFEs used in the last PRA model update based on NRC guidance in Table A-1 of Regulatory Guide 1.200.	HR-G8, HR-I1	Potential impact on risk metrics. Investigate with sensitivity study.
45	Identify any repair related HFEs and apply alternate bases for the values. Review and provide basis for repair probabilities used in the model.	HR-H1, SY-A22, DA-C14, SY-A23	Potential impact on risk metrics. Investigate with sensitivity study.
48	Populate the LGS parameter file with the appropriate data distributions for all entries.	DA-A2, DA-D3, QU-E1, QU-E3	Distributions added for all entries for completeness to perform the parametric uncertainty analysis.
49	Complete URE 1999-048, which should include identification and documentation of the input used for the plant-specific data evaluation.	DA-A3	Potential impact on risk metrics. Investigate with sensitivity study.
52	Collect plant specific data according to the groupings defined by DA-A1 through DA-B2 and document the process.	DA-C2, SY-A13	Potential impact on risk metrics. Investigate with sensitivity study. This was combined with #49.
64	To be consistent with ASME SR DA-D1 and DA-D4, the LGS data analysis needs to be updated to include Bayesian updates using plant specific failures (and use of generic failure rates when plant specific failure information is not available). The Bayesian analysis guidance of ASME SR DA-D4 needs to be included in such an assessment.	DA-D1, DA-D4	Potential impact on risk metrics. Investigate with sensitivity study. This was combined with #49.
77	Complete LGS URE 1999-153 to ensure that the fault tree truncation levels are not impacting the overall event tree quantification results.	QU-B2	Potential impact on risk metrics. Investigate with sensitivity study.

Identification of Key Assumptions

The definitions from Regulatory Guide 1.200, Section 4.2, are used to clarify the nature of the "key assumptions."

> *key assumption:* an assumption made in response to a key source of uncertainty.
>
> *key source of uncertainty:* a source of uncertainty that is related to an issue where there is no consensus approach or model (e.g., choice of data source, success criteria, RCP seal LOCA model, human reliability model) and where the choice of approach or model is known to have an impact on the determination of PRA results in terms of introducing new accident sequences, changing the relative importance of sequences, or affecting the overall CDF or LERF estimates that might have an impact on the use of the PRA in decision making.

Based on these definitions, a list of potential contributors to uncertainty in the PRA was compiled. To develop the key assumption list; however, this list needed to be reduced to examine only those that meet the definition of key sources of uncertainty. Two criteria were established consistent with the definitions above as follows:

- The impact of the uncertainty on the application of the Initiative 5B decision-making process is negligible because it does not impact the related sequences.
- There is a consensus approach and this approach is utilized in the LGS PRA model, therefore, the item is not a key source of uncertainty.

These two criteria were then used to disposition the sources of uncertainty to ascertain the key sources of uncertainty as they impact the decision-making for this Initiative 5b pilot application. An answer of "Yes" to either of the two criteria results in identifying the source of uncertainty as <u>not</u> a key source of uncertainty, as shown below:

Impact on Application is Negligible	Consensus Model or Approach	Key Source of Uncertainty
Yes	N/A	No
No	Yes	No
No	No	Yes

Using this process, the following key sources of uncertainty have been identified for the STI assessments performed thus far:

- Unique Component Data
- Applicability of Generic Data
- Human Reliability Analysis (HRA) Quantification Basis
- Battery Life Assumptions
- Feedwater (FW) Trip given an Anticipated Transient Without Scram (ATWS), i.e., MSIV Isolation Bypass

The first three key sources of uncertainty are applicable to all STI assessments. The battery life assumptions are mostly applicable to those applications related to LOOP scenarios (e.g., EDG

initiation logic relays), and the fifth source of uncertainty is only of concern for those applications related to ATWS scenarios (e.g., RRCS logic modules).

The key assumptions are then evolved from these key sources of uncertainty as shown in Table 3. The 1998 PRA Peer Review Team did not explicitly review a list of assumptions; however, the Peer Review Team's related comments are also shown in Table 3 that clearly indicate their review of the identified key assumptions.

Table 3
IDENTIFICATION OF KEY ASSUMPTIONS FOR THE INITIATIVE 5B PILOT APPLICATION

Key Source of Uncertainty	Key Assumption	Related Peer Review Comments
Applicability of Generic Data	The plant-specific reliability data is currently limited to the EDGs. All of the other reliability data is from generic sources. As such, this is noted as a key area of uncertainty for the application. The key assumption is that the use of mostly generic data is acceptable to characterize the risk metrics for the application.	There was one 'B' F&O related to the use of generic data from the 1999 certification report. The F&O noted that the use of plant-specific data was limited to the EDGs, and that generic data was used for all other systems. It was noted that the collection of plant-specific data, especially for Maintenance Rule risk significant systems, would be a beneficial addition to the model. There has been no action to date, but a major update for plant-specific data and the corresponding common cause analysis is planned as part of the 2004 update.
Unique Component Data	Standby failure terms have been added to the model to support the application. As is standard PRA practice, these failure terms are assumed to increase in magnitude as the surveillance test interval is increased. The key assumption is that the chosen representative standby failure rates are appropriate for each interval extension request assessment.	Since the standby failure values utilized for the surveillance interval extension assessments were added specifically to support the assessment, there were no related peer review comments.

Table 3

IDENTIFICATION OF KEY ASSUMPTIONS FOR THE INITIATIVE 5B PILOT APPLICATION

Key Source of Uncertainty	Key Assumption	Related Peer Review Comments
HRA Quantification Basis	The human error probabilities included in the model were developed at different time frames, and therefore a consistent methodology has not been used for all of the actions. The number of operator actions modeled in the LGS at-power PRA, and the level of detail of the HRA, is sufficient to characterize the risk significant accident sequences. However, although the number of actions is comprehensive, it is noted as a key area of uncertainty for the application based on the varying levels of pedigree for the human actions. The key assumption then becomes that the use of varying HRA methodologies does not adversely skew the overall results.	There were two related F&Os that were both assigned 'C' levels of significance. Updates on selected HEP values have been made over the last two PRA model updates. A strength was noted by the peer review for the methodology and partial HRA update performed prior to the certification. This methodology has been employed in the subsequent update, but there are still a number of HEP values that are based on older/different methodologies. A major update of all significant HEP values is planned as part of the 2004 PRA update.
Battery Life Assumptions	The LOOP event trees in the current model are structured to credit just two hours of battery life per division. This assumption is based on lack of clear evidence that they would last longer than that as identified in the 1999 peer certification report. The key assumption is that battery life is limited to two hours per division. This assumption may be conservative and tend to increase the CDF and LERF contribution from LOOP events.	There were two related F&Os that were both assigned 'C' levels of significance, and one related 'B' F&O. The LOOP event trees were revised in the last update to reflect a shorter available battery life assumption. This assumption may be conservative and tend to increase the CDF and LERF contribution from LOOP events.
FW Trip given ATWS (MSIV Isolation Bypass)	MSIV interlock bypass is part of the current ATWS event tree modeling, but the analysis and HEP values have not been updated with more current methodologies. The HEP value of 0.65 may be masking the importance of RRCS that may be influencing the RRCS surveillance test interval extension assessment. The key assumption is that given failure of HPCI, there is a high failure probability associated with maintaining level after success of RRCS for feedwater runback to avoid MSIV closure on low level. MSIV closure would then cause feedwater to trip.	There were two related F&Os that were both assigned 'B' levels of significance. In response to these findings, justification (i.e., reference sources) for all ATWS timing and assumptions were compiled as part of the last update. MSIV interlock bypass is part of the current ATWS event tree modeling, but the analysis and HEP values have not been updated with more current methodologies.

Resolution of Peer Review Comments

Currently, there are no 'A' and only two remaining 'B' F&O items to be addressed or dispositioned. These items were reviewed to assess their impact on this application. Table 4 summarizes the results of that investigation. In summary, only one item was identified as potentially impacting this application (i.e., the acceptability of using mostly generic data). This has already been identified as a key area of uncertainty and has been subject to a sensitivity study as discussed later. The other remaining open item does not affect the PRA model and would not alter the STI assessments.

Table 4
IMPACT OF IMPORTANT OPEN PEER REVIEW FINDINGS

Observation	Impact on the LGS PRA
Plant specific failure data was analyzed only for the EDGs. Generic failure data was used for all other systems.	This has a potential impact on the application. The acceptability of the use of mostly generic data to characterize the risk metrics for the application has been identified as a key assumption. Also note that an extensive plant-specific data analysis effort is planned as part of the 2004 PRA update.
The dependency diagram does not show the dependency of RHRSW and ESW pumps on spray pond pump house ventilation.	No impact. This is a documentation issue only. Extensive system notebooks are being developed as part of the 2004 PRA update.

Sensitivity Study Results

To support the PRA quality assessment, sensitivity studies were performed for generically applicable issues and also for focused issues identified from the development of the key assumption list. The results from these studies are discussed in this section.

Typically, bounding assessments were performed to explore the potential uncertainty associated with the issue. The highest increase occurs from the highly unlikely case of increasing the post-initiator HEPs by a factor of 10 or the lower bound for the HEP combinations by a factor of 10. All of the other cases lead to less than a 40% change in the core damage frequency (CDF) and large early release frequency (LERF) values.

To provide additional insights on the dominant accident sequences and contributors, a review was performed of the dominant accident class and event scenario contribution for those cases that resulted in at least a 10% change in the calculated CDF. In general, there was not a substantial difference in the distributions except in a few cases. In those cases, the change is due to the Station Blackout (SBO) contribution change based on a bounding assessment assumption for the sensitivity case. The change in SBO contribution can be characterized from increases in other contributions or a change to the SBO contribution directly. In either case, the dominant contributors remain to be from the same set of five accident classes.

In summary, addressing all of the open items and issues associated with the LGS PRA model may lead to a net increase or decrease in the total CDF and LERF values. However, with reasonable (i.e., not bounding or overly-conservative) changes made to any of the contributors identified in the sensitivity studies, the overall distribution of significant accident sequences is not expected to substantially change. Additionally, the current base model dominant contributors and accident sequences are fairly consistent with other Boiling Water Reactor (BWR) PRA models. Therefore, it is not expected that changes to the model would impact the conclusions from the revised STI assessments, especially when the calculated change in the risk metrics is very small.

In addition to the generic sensitivity studies performed above, the identification of the key assumptions led to three additional issues not previously identified from the original assessment based on the Gap Analysis findings. The issues associated with the applicability of using mostly generic data in the model and the varying methodologies used for the development of the HEP values were investigated as part of the generic sensitivity studies described above. The three additional issues are as follows:

- Unique Component Data
- Battery Life Assumptions
- FW Trip given ATWS (MSIV Isolation Bypass)

Each of these is discussed in turn.

Unique Component Data

Each of the STI assessments is contingent upon the use of applicable standby failure rates in the evaluation. The main source of information is chosen consistent with the Exelon Risk Management Team philosophy for best available data. Additionally, the Initiative 5b process includes steps to investigate that the components of interest for the STI assessment have not been subject to noted bad performance. If there has been acceptable performance, then it is judged that the generic standby failure rates are applicable.

However, as the intervals are extended beyond current practices, the potential uncertainty associated with the standby failure rates increases. As such, the process includes a separate sensitivity in each assessment to include standby failure rates at the 95th percentile value (approximately a factor of three higher than the mean failure rate) to determine the potential increase in the risk metrics if this value is used instead of the accepted generic mean value. The results of this assessment plus other qualitative considerations are all used as input to the Integrated Decisionmaking Panel process in determining if the extension request is acceptable, and if it is acceptable, whether a phased approach is preferred over an immediate change to the STI.

Battery Life Assumptions

A key assumption in the current model is that battery life is limited to two hours per division. This assumption is based on lack of clear evidence that they would last longer than that as identified in the 1999 peer certification report.

This assumption may be conservative and tend to increase the CDF and LERF contribution from LOOP events. As such, it may lead to overstating the change in the risk metrics (i.e., delta CDF and delta LERF) in those assessments that involve LOOP related components or systems (e.g., the EDG initiation logic). This is not a concern for very small changes in the calculated risk metrics such as those that have been performed thus far, but could be an issue in cases where a significant amount of margin does not exist.

FW Trip given ATWS (MSIV Isolation Bypass)

MSIV interlock bypass is part of the current ATWS event tree modeling, but the analysis and HEP values have not been updated with more current methodologies. The HEP value of 0.65 may be masking the importance of RRCS that may be influencing the RRCS STI assessment. The key assumption is that given failure of high pressure coolant injection (HPCI) system, there is a high failure probability associated with maintaining level after success of RRCS for feedwater runback to avoid MSIV closure on low level. MSIV closure would then cause feedwater to trip.

To investigate the sensitivity to this current assumption, the assessment for the RRCS STI extension was re-performed utilizing a model that includes a much lower probability for the HEP value (i.e., 1E-2) associated with failing to control level after runback above the MSIV closure setpoint. The results of that analysis showed that although there is some change associated with the base case CDF and LERF values, the change in the risk metrics from the assessment are the same. Thus, the uncertainty associated with the HEP value for controlling level following feedwater runback does not have an impact on the conclusions from the original assessment.

PRA Quality Assessment Conclusions

The specific PRA application for which this PRA quality assessment is being developed is the LGS pilot application for BWROG Initiative 5b. This initiative allows for control of surveillance test *intervals* to be maintained within a separate program outside of the current Technical Specifications while maintaining the surveillance test *activities* within the Technical Specifications.

The primary risk contributors affecting the risk metrics associated with this application depend upon the particular STI that is being considered. However, the extension requests are narrowly focused such that the estimated change in the calculated CDF and LERF can be adequately assessed. Additionally, uncertainty assessments are performed as part of each STI extension request to ensure that undue reliance on particular assumptions or aspects of the modeling is not made in determining the acceptability of the revised interval.

The results of the risk assessment plus other qualitative considerations are all used as input to the Integrated Decisionmaking Panel process in determining if the extension request is

acceptable, and if it is acceptable, whether a phased approach is preferred over an immediate change in the interval.

In summary, the LGS PRA model is of sufficient quality to be exercised and used to support the Initiative 5b process.

References

(1) U.S. Nuclear Regulatory Commission, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Regulatory Guide 1.200 For Trial Use, February 2004.

(2) NRC Generic Letter 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR 50.54(F)*, November 23, 1988

(3) American Society of Mechanical Engineers, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications,* ASME RA-S-2002, April 2002 and Addenda in ASME RA-Sa-2003, December 2003.