NEXTera ENERGY
DUANE ARNOLD

November 20, 2025
L-2025-182
10 CFR 50.90

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

Duane Arnold Energy Center
Docket No. 50-331
Renewed Facility License No. DPR-49

License Amendment Request (TSCR-196): Application to Revise the Renewed Facility License and Technical Specifications to Support Resumption of Power Operation

References:

1. Letter from NextEra Energy Duane Arnold, LLC to USNRC, "Certification of Permanent Removal of Fuel from the Reactor Vessel for Duane Arnold Energy Center," dated October 12, 2020 (ADAMS Accession No. ML20286A317)
2. Letter from NextEra Energy Duane Arnold, LLC to USNRC, "Regulatory Path to Potential Reauthorization of Power Operations," dated January 23, 2025 (ADAMS Accession No. ML25023A265)
3. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “Request for Exemption from Certain Termination of License Requirements of 10 CFR § 50.82,” dated January 23, 2025 (ADAMS Accession No. ML25023A270)
4. Letter from USNRC to NextEra Energy Duane Arnold, LLC, “Notice of Availability of the Final Plant-Specific Supplement 42 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) Regarding Duane Arnold Energy Center”, dated October 7, 2010 (ADAMS Accession No. ML102720134)

Pursuant to 10 CFR 50.90, NextEra Energy Duane Arnold, LLC (NEDA) is submitting a license amendment request (LAR) to revise the Duane Arnold Energy Center (DAEC) Renewed Facility License (RFL), the Appendix A Technical Specifications (TS) and the Appendix B Additional Conditions. This LAR requests revisions to the RFL and the TS to reflect the resumption of power operations at DAEC.

The DAEC facility license has not been terminated and remains valid, though it currently does not authorize operation. The transition of DAEC from an operating nuclear plant to a facility in decommissioning occurred on October 12, 2020, when the 10 CFR § 50.82(a)(1)(ii) certification was docketed (Reference 1). On May 31, 2022, other previously approved license amendments and exemptions that reduced regulatory requirements to facilitate decommissioning at DAEC were implemented. NextEra has not commenced a "major decommissioning activity" at DAEC, as defined by 10 CFR 50.2, "Definitions".

Reference 2 describes the regulatory path NextEra intends to follow to support the restoration of the previous DAEC licensing basis and reauthorization of power operations at DAEC. The NRC review of these submittals, along with reinstatement of the oversight process applicable to operating reactors, will ensure that DAEC will only be authorized to resume operations if the NRC has reasonable assurance that it can do so in a manner that protects public health and safety in conformance with DAEC's operating licensing basis. The first action in this regulatory path is a request for a one-time exemption from 10 CFR 50.82(a)(2). This request was submitted in Reference 3. With this exemption, the DAEC licensing basis in effect prior to the 10 CFR 50.82 certifications can be restored through the 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit", license amendment request process for the DAEC RFL, TSs, and other programmatic requirements.

Enclosure 1 to this letter provides NEDA's evaluation of the proposed change. Attachment 1 to the enclosure provides markups of the TS showing the proposed changes (mark up pages), and Attachment 2 provides the clean TS pages that incorporate the proposed TS changes. The reinstated TS Bases are provided for information in Attachment 3 and will be incorporated in accordance with the reinstated TS Bases Control Program upon implementation of the approved amendment.

To coordinate implementing this LAR, consistent with IMC 2562, NextEra plans to submit a notification of readiness to transition to power operations letter to the NRC certifying that the exemption implementation conditions and the license amendments effectiveness conditions are met, and that the 10 CFR 50.82(a)(1) certifications are rescinded. Pursuant to IMC 2562, after NRC documents the licensee's readiness to restart, all inspection cornerstones are transitioned back to the Reactor Oversight Process, all operating licensing actions are implemented, and NextEra makes a final decision to restart operations, DAEC will transition back to a power operations plant.

This letter contains no new and no revised regulatory commitments.

In accordance with 10 CFR 50.91, a copy of this application with the enclosure is being provided to the designated State of Iowa official.

As discussed in Enclosure 1, the proposed change does not involve a significant hazards consideration pursuant to 10 CFR 50.92, and there are no significant environmental impacts associated with the change. The DAEC Safety Review Group has reviewed the proposed license amendment.

If you have any questions or require additional information, please contact Robert Murrell, Licensing Project Manager, at 319-651-9496.

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

Executed on November 20, 2025

Kenneth Mack
Director, Licensing and Regulatory Compliance
Nuclear Fleet

Enclosure:

1. License Amendment Request, Description and Evaluation of the Proposed Changes

cc: NRC Region III Administrator
NRC Decommissioning Inspector
NRC NMSS Project Manager
Designated Iowa State Official

Enclosure 1

NEXTERA ENERGY DUANE ARNOLD, LLC
DUANE ARNOLD ENERGY CENTER

L-2025-182

LICENSE AMENDMENT REQUEST (TSCR-196)

DESCRIPTION AND EVALUATION OF THE PROPOSED CHANGES

NEXTERA ENERGY DUANE ARNOLD, LLC
DUANE ARNOLD ENERGY CENTER

License Amendment Request (TSCR-196): Application to Revise the Renewed Facility License and Technical Specifications to Support Resumption of Power Operation

EVALUATION OF PROPOSED CHANGE

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Attachment 1 – Proposed Operating License and Technical Specification Changes (Mark-Up)
Attachment 2 – Revised Operating License and Technical Specification Pages (Clean, with Proposed Changes)
Attachment 3 – Proposed Technical Specification Bases

1.0 SUMMARY DESCRIPTION

NextEra Energy Duane Arnold, LLC (NEDA) requests a license amendment to revise the Duane Arnold Energy Center (DAEC) Renewed Facility License (RFL) and the Appendix A Technical Specifications (TS). The Appendix B Additional Conditions also require revision as described in Section 3. This LAR requests revisions to the RFL and the TS to reflect the resumption of power operations at DAEC.

The proposed changes reinstate DAEC license requirements that were removed based on docketing the certifications of permanent cessation of power operations and permanent removal of fuel from the reactor vessel (10 CFR 50.82(a)(1) Certifications) to support a return of the DAEC plant to power operations. The requested changes involve no significant hazards consideration.

2.0 DETAILED DESCRIPTION

2.1 Reason for Proposed Change

The DAEC facility license has not been terminated and remains valid, though it currently does not authorize operation. The transition of DAEC from an operating nuclear plant to a facility in decommissioning occurred on October 12, 2020, when the 10 CFR 50.82(a)(1)(ii) certification was docketed (Reference 1). On May 31, 2022, other previously approved license amendments and exemptions that reduced regulatory requirements to facilitate decommissioning at DAEC were implemented. NextEra has not commenced a "major decommissioning activity" at DAEC, as defined by 10 CFR 50.2, "Definitions".

Reference 2 describes the regulatory path NextEra intends to follow to support the restoration of the previous DAEC licensing basis and reauthorization of power operations at DAEC. The NRC review of these submittals, along with reinstatement of the oversight process applicable to operating reactors, will ensure that DAEC will only be authorized to resume operations if the NRC has reasonable assurance that it can do so in a manner that protects public health and safety; in conformance with DAEC's operating licensing basis. The first action in this regulatory path is a request for a one-time exemption from 10 CFR 50.82(a)(2). This request was submitted in Reference 3. With this exemption, the DAEC licensing basis in effect prior to the 10 CFR 50.82 certifications can be restored through the 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit", license amendment request process for the DAEC RFL, TSs, and other programmatic requirements.

As described above, this LAR is necessary to reinstate the DAEC RFL and TS that were in effect prior to Amendment 309 (Reference 5) to support returning DAEC to a power operations licensing basis

2.2 Description of Proposed Change

This LAR will revise the DAEC RFL and the TSs. The proposed changes are consistent with the emplacement of fuel into the reactor vessel and resumption of power operation at DAEC. The proposed changes would revise certain requirements contained within the DAEC RFL and TS to reinstate requirements that are necessary for power operation and revise or remove

requirements that would no longer be applicable. The proposed changes to the DAEC TS are in accordance with 10 CFR 50.36(c)(1) through 10 CFR 50.36(c)(5).

The Updated Final Safety Analysis Report (UFSAR), Revision 25, is the pre-shutdown design basis of record for the operational unit and supports the proposed action. UFSAR Rev. 25 was submitted to the NRC on March 21, 2019 (Reference 4).

Following the 10 CFR 50.82(a)(1) certifications to reflect the permanent shutdown status of the facility, Revision 25 of the UFSAR was revised to be the Defueled Safety Analysis Report (DSAR), Revision 0. UFSAR Revision 26 was used for documentation purposes at the site after the DSAR Revision 0 was issued. The DSAR has been maintained in accordance with 10 CFR 50.59, "Changes, tests and experiments." The current revision to the DSAR will continue to be submitted to NRC in accordance with the recurring timeframe specified by 10 CFR 50.71(e) until approval of the 10 CFR 50.82(a)(2) Exemption Request.

The UFSAR is being restored as draft Revision 27 which reflects the pre-shutdown Revision 25, including reinstatement of the SSC safety classifications and applicable accident analyses, with some anticipated changes. Anticipated changes are subject to 10 CFR 50.59 reviews and would be submitted to the NRC for approval in support of this amendment if required. DAEC intends to submit the UFSAR Revision 27 to the NRC at an appropriate time to be determined by NRC.

3.0 TECHNICAL EVALUATION

This LAR proposes modifications to the DAEC RFL and the TSs to support the reinstatement of power operation at DAEC.

The regulatory requirements related to the content of TSs are promulgated in 10 CFR 50.36, *Technical Specifications*. As detailed in a subsequent section of this LAR, this regulation lists the criteria to define the scope of items that must be included in TS. The scope of SSCs and parameters that must have Limiting Conditions for Operation (LCO) included in the DAEC TS to support the operating licensing basis are those needed to address the reinstated draft UFSAR Revision 27 postulated design basis accidents (DBAs) so that the consequences of the DBAs are maintained within acceptable limits. DAEC TS LCOs that were removed in Amendments 309, 311 and 315 (References 5, 6 and 7) will be reinstated to support the DAEC draft UFSAR Revision 27.

3.1 Accident and Transient Analyses Applicable to the Proposed Change

UFSAR Chapter 15 also describes the analyses that were performed to demonstrate that the plant could be operated safely and that radiological consequences from postulated DBAs do not exceed applicable limits. The most severe postulated accidents for nuclear power plants involve damage to the nuclear reactor core and the release of large quantities of fission products to the RCS. Many of the accident scenarios postulated in the UFSAR involve failures or malfunctions of systems which could affect the reactor core. Once the reactor is permitted to be refueled and resumes power operation, these UFSAR events are applicable.

The analyses in UFSAR Chapter 15 provide results that are compared to regulatory acceptance criteria and are integral to the plant's design and licensing basis. These analyses demonstrate the integrity of the fission product barriers, the capability to shut down the reactor and maintain it

in a safe shutdown condition, and the capability to prevent or mitigate the consequences of DBAs and transients. Certain systems, structures, and components (SSCs) are credited in these analyses for the purpose of mitigating the DBAs or transients. These SSCs are considered for inclusion in TS per the requirements of 10 CFR 50.36(c).

As noted above, the UFSAR will be reinstated as draft Revision 27 which is consistent with the last docketed version of the UFSAR that was in effect prior to the 10 CFR 50.82(a)(1) certifications. This includes reinstatement of the DBA and transient scenarios in Chapter 15. These scenarios and analyses will be reinstated as they existed in Revision 25 of the UFSAR. No changes to these analyses are made as part of the return to power for DAEC.

As a normal part of evaluating core designs and operational parameters, reviews of Chapter 15 sections are performed for each fuel reload cycle by the nuclear fuel vendor to determine if the proposed core design is still bounding or if it needs to be reanalyzed. The UFSAR is updated accordingly, as needed. Therefore, future changes to Chapter 15 of the UFSAR may occur separately from the licensing actions necessary to resume power operation and will be evaluated under the 10 CFR 50.59 process against the DAEC operating licensing basis.

In Reference 8, DAEC discussed one accident analysis that remained valid for a permanently shut down and defueled condition. It is the fuel handling incident. In a supplement to that LAR (Reference 9), the fuel handling accident was revised. The revised fuel handling accident analysis was approved by the NRC in Reference 6. With the return to power operation, this approved fuel handling analysis is no longer applicable since it only addresses the permanently shut down condition. Therefore, the fuel handling accident analysis will be restored to the version in UFSAR Revision 25 reflecting an operational plant.

A list of Chapter 15 events is provided in Table 3.1 below.

Table 3.1

UFSAR Section	Postulated Accident or Transient
15.1	**Transients**
15.1.1	Transients Resulting in a Reactor Vessel Water Temperature Decrease
15.1.1.1	Feedwater Controller Failure – Maximum Demand
15.1.1.2	Loss of Feedwater Heating
15.1.1.3	Inadvertent HPCI Actuation
15.1.2	Transients Resulting in a Nuclear System Pressure Increase
15.1.2.1	Generator Load Rejection (Turbine Control Valve Fast Closure)
15.1.2.1.1	Main Generator Load Rejection with Bypass Valve (LRWBP) – High Power
15.1.2.1.2	Main Generator Load Rejection with Bypass Valve Failure (LRNBP) – High Power
15.1.2.1.3	Generator Load Rejection from Low Power Without Bypass
15.1.2.2	Turbine Trip (Turbine Stop Valve Closure)
15.1.2.2.1	Main Turbine Trip with Bypass (TTWBP) – High Power
15.1.2.2.2	Main Turbine Trip with Bypass Valve Failure (TTNBP) – High Power
15.1.2.2.3	Main Turbine Trip with Bypass Valve Failure (TTNBP) – Low Power
15.1.2.3	Main Steam Line Isolation Valve Closure
15.1.2.3.1	Closure of all Main Steam Line Isolation Valves (MSIV) – High Power
15.1.2.3.2	Closure of All Main Steam Line Isolation Valves with direct Scram Failure (MSIVF) – High Power
15.1.2.3.3	Closure of One Main Steam Line Isolation Valve (1 MSIV) – High Power
15.1.3	Transients Resulting in a Core Coolant Flow Decrease
15.1.3.1	Recirculation Flow Control Failure – Decreasing Flow
15.1.3.2	Trip of One Recirculation Pump
15.1.3.3	Trip of Two Recirculation Pumps
15.1.4	Transients Reactivity And Power Distribution Anomalies
15.1.4.1	Rod Withdrawal Error at Power
15.1.4.2	Rod Withdrawal Error at Startup
15.1.4.3	Control Rod Removal Error During Refueling
15.1.4.4.1	Fuel Assembly Insertion Error During Refueling – Inadvertent Criticality
15.1.4.4.2	Fuel Loading Error – Mislocated Bundle
15.1.4.4.3	Fuel Loading Error – Rotated Bundle
15.1.5	Transients Resulting in an Increase in Core Flow
15.1.5.1	Startup of an Idle Recirculation Pump
15.1.5.2	Recirculation Flow Controller Failure – Increasing Flow (Fast)
15.1.5.3	Recirculation Flow Controller Failure – Slow Flow Runout
15.1.6	Transients Resulting in an Increase in Reactor Coolant Inventory
15.1.7	Transients Resulting in a Reactor Vessel Coolant Inventory Decrease
15.1.7.1	Pressure Regulator Failure – Open
15.1.7.2	Inadvertent Opening of a Safety/Relief Valve
15.1.7.3	Loss of Feedwater Flow
15.1.7.4	Trip of One Feedwater Water Pump

UFSAR Section	Postulated Accident or Transient
15.2	**Accidents**
15.2.1	Loss-Of-Coolant Accidents
15.2.1.1	Reactor Recirculation Pipe Breaks
15.2.1.2	Core Spray Line Break
15.2.1.3	Feedwater Line Break
15.2.1.4	Main Steam Line Break – Inside Containment
15.2.1.5	Main Steam Line Break – Outside Containment
15.2.2	Instrument Line Breaks
15.2.3	Recirculation Pump Seizure Accident
15.2.4	Control Rod Drop Accident
15.2.5	Fuel Handling Accident

UFSAR Section	Postulated Accident or Transient
15.3	**Special Events**
15.3.1	Anticipated Transients Without Scram (ATWS)
15.3.1.1	ATWS – MSIVC
15.3.1.2	ATWS – PRFO
15.3.1.3	ATWS – LOOP
15.3.1.4	ATWS – IORV
15.3.2	Station Blackout (SBO)
15.3.2.1	Station Blackout (SBO)
15.3.3	Fire – Safe Shutdown Analysis
15.3.3.1	Fire – No Spurious Operations
15.3.3.2	Fire – Spurious Opening of One S/RV (20 Mins)
15.3.3.3	Fire – Spurious Opening of One S/RV (10 Mins)
15.3.3.4	Fire – With Leakage from a One Inch Line
15.3.4	Thermal-Hydraulic Stability
15.3.4.1	Thermal-Hydraulic Stability – Exclusion/Buffer Zone Determination
15.3.4.2	Thermal-Hydraulic Stability – Safety Limit MCPR Protection
15.3.5	Analysis of Reactor Internals Pressure Differentials (RIPD)
15.3.5.1	RIPD – Normal Limits
15.3.5.2	RIPD – Upset Limits
15.3.5.3	RIPD – Emergency Limits
15.3.5.4	RIPD – Faulted Limits
15.3.5.5	RIPD – Flow-Induced Loads
15.3.5.6	RIPD – Acoustic Loads

3.2 Evaluation of the Proposed Change

DAEC proposes modifying the DAEC RFL and TS as shown below. Each section that is proposed to be changed is identified, the proposed changes are shown, and the basis for each change is given. Changes to the RFL are listed first followed by a discussion of the Additional Conditions and then changes to the TS. If appropriate, proposed deletions are shown with strikethrough and additions are underlined. TS sections that were deleted in their entirety with issuance of Amendment 311 and 315, (References 6 and 7) are proposed for reinstatement to

create TS sections consistent with power operation. The addition of these complete TS sections is described below.

Attachment 1 to this enclosure contains a mark-up of the current RFL and TS pages. The proposed changes to the TS are considered a major rewrite with the addition of numerous TS. Revision bars are not used. TS sections that are added in their entirety are listed by number and title, however the inserted TS pages are not included with the marked-up pages in Attachment 1. In addition, the following editorial changes are not shown in the marked-up RFL and TS in Attachment 1 because they do not affect the technical content of the RFL or TS:

- Reformatting (margins, font, tabs, line spacing, removal of blank pages, format consistent with Improved Standard TS, etc.) content to create a continuous electronic file,
- Renumbering of pages and change in page numbering scheme, where appropriate, and
- Removal of historical amendment numbers.

Attachment 2 of this enclosure provides the re-typed and added pages to reflect the proposed changes in their entirety.

The TS Bases were deleted in their entirety as described in Reference 10. The TS Bases sections that will be reinstated are provided in Attachment 3 and are the version that was in effect prior to Amendment 309. They are provided for information only. Upon approval of this amendment, the TS Bases will be reinstated and future changes to the TS Bases will be incorporated in accordance with the reinstated DAEC TS 5.5.10, "Technical Specifications (TS) Bases Control Program." Since the reinstatement of the TS Bases are considered a major rewrite, revision bars are not used.

3.2.1 Proposed Changes to the DAEC Renewed Facility License

Changes proposed to the RFL are necessary to reinstate certain License Conditions that were removed or revised by license amendments 311, 312, 314, 315, 316, and 317 (References 6, 11, 12, 7, 13 and 14) due to docketing the 10 CFR 50.82 decommissioning certifications and removal of fuel from the spent fuel pool. All current License Conditions are addressed below, even if no change is requested. No changes are proposed to the previously approved license conditions that are being reinstated.

LICENSE	
License Title	
Current Title Renewed Facility License	Proposed Title Renewed Facility Operating License
Basis	
This license title is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.A	
Current The application for license filed by FPL Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative (the licensees) complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;	No change proposed.
Basis	
No change is needed for this License Condition as it addresses conformance with the Atomic Energy Act and regulations. This License Condition was not revised by any decommissioning related actions.	

License Condition 1.B	
Current Deleted.	No change proposed.
Basis	
License Condition 1.B is not reinstated because the operation of DAEC does not depend on the conformity with Construction Permit No. DPPR-70. On February 22, 1974 (ADAMS Accession No. ML021860274), the Atomic Energy Commission issued Facility Operating License No. DPR-49 to the licensee. Construction Permit No. DPPR-70 was superseded by Facility Operating License No. DPR-49, which eventually became Renewed Facility Operating License (RFOL) No. DPR-49, dated December 16, 2010 (ADAMS Accession No. ML110980120). Therefore, it is acceptable not to reinstate License Condition 1.B.	

License Condition 1.C	
Current The facility will be maintained in conformity with the application, as amended; the provisions of the Act; and the rules and regulations of the Commission;	Proposed The facility will operate ~~be maintained~~ in conformity with the application, as amended; the provisions of the Act; and the rules and regulations of the Commission;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.D	
Current There is reasonable assurance: (i) that the activities authorized by this renewed license can be conducted without endangering the health and safety of the public; and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;	Proposed There is reasonable assurance: (i) that the activities authorized by this renewed operating license can be conducted without endangering the health and safety of the public; and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.E	
Current NextEra Energy Duane Arnold, LLC is technically qualified and NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative are financially qualified to engage in the activities authorized by this renewed license in accordance with the rules and regulations of the Commission;	Proposed NextEra Energy Duane Arnold, LLC is technically qualified and NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative are financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.F	
Current The licensees have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;	No change proposed.
Basis	
No change is needed for this License Condition as it addresses conformance with regulations. This License Condition was not revised by any decommissioning related actions.	

License Condition 1.G	
Current The issuance of this renewed license will not be inimical to the common defense and security or to the health and safety of the public;	Proposed The issuance of this renewed operating license will not be inimical to the common defense and security or to the health and safety of the public;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.H	
Current After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of renewed Facility License No. DPR-49 is in accordance with 10 CFR Part 50, Appendix D, of the Commission's regulations and all applicable requirements of said Appendix D have been satisfied;	Proposed After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of renewed Facility Operating License No. DPR-49 is in accordance with 10 CFR Part 50, Appendix D, of the Commission's regulations and all applicable requirements of said Appendix D have been satisfied;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 1.I	
Current Deleted.	Proposed ~~Deleted.~~ The receipt, possession, and use of source, by-product and special nuclear material as authorized by this renewed operating license will be in accordance with the Commission's regulations in 10 CFR Part 30 and 70, including 10 CFR Section 30.33, 70.24 and 70.31.
Basis	
This license condition is reinstated to authorize the receipt, possession and use of byproduct, source, and special nuclear material. This reinstatement is consistent with the fact that DAEC will become a power operation plant and use of this material is necessary for plant functions.	

License Condition 2	
Current Renewed Facility License No. DPR-49 is hereby issued to NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative (CIPCO) and Corn Belt Power Cooperative (Corn Belt) to read as follows:	Proposed Renewed Facility Operating License No. DPR-49 is hereby issued to NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative (CIPCO) and Corn Belt Power Cooperative (Corn Belt) to read as follows:
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 2.A	
Current (first sentence only) This renewed license applies to the Duane Arnold Energy Center, a permanently defueled boiling water reactor and associated equipment (the facility), owned by NextEra Energy Duane Arnold, LLC, Central Iowa	Proposed (first sentence only) This renewed operating license applies to the Duane Arnold Energy Center, a ~~permanently defueled~~ boiling water reactor and associated equipment (the facility), owned by NextEra Energy Duane Arnold, LLC, Central Iowa

Power Cooperative and Corn Belt Cooperative and operated by NextEra Energy Duane Arnold, LLC. The remaining sentences in Condition 2.A are unchanged.	Power Cooperative and Corn Belt Cooperative and operated by NextEra Energy Duane Arnold, LLC. The remaining sentences in Condition 2.A are unchanged.
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 2.B(1)	
Current NextEra Energy Duane Arnold, LLC, pursuant to Section104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess and use the facility as required for nuclear fuel storage; and CIPCO and Corn Belt to possess the facility at the designated location in Linn County, Iowa, in accordance with the procedures and limitations set forth in this license;	Proposed NextEra Energy Duane Arnold, LLC, pursuant to Section104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, ~~and~~ use and operate the facility ~~as required for nuclear fuel storage~~; and CIPCO and Corn Belt to possess the facility at the designated location in Linn County, Iowa, in accordance with the procedures and limitations set forth in this license;
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 2.B(2)	
Current NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Updated Final Safety Analysis Report, as supplemented and amended as of June 1992 and as supplemented by letters dated March 26, 1993, and November 17, 2000.	Proposed NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material ~~that was used~~ as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Updated Final Safety Analysis Report, as supplemented and amended as of June 1992 and as supplemented by letters dated March 26, 1993, and November 17, 2000.
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50 and use of this material is necessary for plant functions as described.	

License Condition 2.B(3)	
Current	Proposed

NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source or sealed sources for radiation monitoring equipment calibration and to possess any byproduct, source and special nuclear material as sealed neutron sources previously used for reactor startup and reactor instrumentation, and fission detectors;	NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, or sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required ~~and to possess any byproduct, source and special nuclear material as sealed neutron sources previously used for reactor startup and reactor instrumentation; and fission detectors~~;
Basis	
This license condition is reinstated to authorize the receipt and use of byproduct, source, and SNM as sealed neutron sources for reactor startup, and reactor instrumentation. This reinstatement is consistent with the fact that DAEC will become a power operation plant and use of this material is necessary for plant functions as described.	

License Condition 2.B(4)	
Current NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated radioactive apparatus components;	No change proposed.
Basis	
No change is needed for this License Condition as it allows the receipt, storage and use of byproduct, source and special nuclear material. This License Condition was not revised by any decommissioning related actions.	

License Condition 2.B(5)	
Current NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not to separate, such byproduct and special nuclear materials that were produced by the operation of the facility.	Proposed NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not to separate, such byproduct and special nuclear materials as may be ~~that were~~ produced by the operation of the facility.
Basis	
This license condition is reinstated to reflect that DAEC will become a power operation plant and produce byproduct and special nuclear materials in the course of plant operation.	

License Condition 2.C	
Current This renewed operating license shall	No change proposed.

be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I; Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:	
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 2.C(1)	
Current Deleted.	Proposed ~~Deleted.~~ Maximum Power Level NextEra Energy Duane Arnold, LLC is authorized to operate the Duane Arnold Energy Center at steady state reactor core power levels not in excess of 1912 megawatts (thermal).
Basis	
This License Condition is reinstated to reflect the operating condition. The maximum power level is defined in this License Condition and is consistent with that used to support the accident analyses evaluated in the UFSAR.	

License Condition 2.C(2)	
Current Technical Specifications The Technical Specifications contained in Appendix A, as revised through Amendment No. 317, are hereby incorporated in the license. NextEra Energy Duane Arnold, LLC shall maintain the facility in accordance with the Permanently Defueled Technical Specifications.	Proposed Technical Specifications The Technical Specifications contained in Appendix A, as revised through Amendment No. ~~317~~ XXX, are hereby incorporated in the license. NextEra Energy Duane Arnold, LLC shall operate ~~maintain~~ the facility in accordance with the ~~Permanently Defueled~~ Technical Specifications.
Basis	
License Condition 2.C(2) is reinstated as noted below for 2.C(2)(a) and 2.C(2)(b). This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50. The current amendment number is deleted and replaced with "XXX" which acts as a placeholder for the new amendment number associated with the approval of this LAR.	

License Condition 2.C(2)(a) is not reinstated. It is a historical Condition whose actions have been performed. Amendment 243 was approved on November 6, 2001 (Reference 15). Surveillance Requirements that were addressed in that Amendment have been performed in the intervening interval. None of the Surveillance Requirements had a Frequency longer than 24 months and it has been more than 24 months (plus any extension) since implementation of the Amendment. Therefore, this historical Condition does not need to be reinstated.

License Condition 2.C(2)(b) was previously deleted and the placeholder for that previous deleted Condition is not reinstated.

License Condition 2.C(3)	
Current Deleted.	Proposed Fire Protection Program ~~Deleted.~~ NextEra Energy Duane Arnold, LLC shall implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c), as specified in the licensee amendment request dated August 5, 2011 (and supplements dated October 14, 2011, April 23, 2012, May 23, 2012, July 9, 2012, October 15, 2012, January 11, 2013, February 12, 2013, March 6, 2013, May 1, 2013, May 29, 2013, two supplements dated July 2, 2013, and supplements dated August 5, 2013 and August 28, 2013) and as approved in the safety evaluation report dated September 10, 2013. Except where NRC approval for changes or deviations is required by 10 CFR 50.48(c), and provided no other regulation, technical specification, license condition or requirement would require prior NRC approval, the licensee may make changes to the fire protection program without prior approval of the Commission if those changes satisfy the provisions set forth in 10 CFR 50.48(a) and 10 CFR 50.48(c), the change does not require a change to a technical specification or a license condition, and the criteria listed below are satisfied…. The remainder of the License Condition is found in Attachment 1.
Basis	
This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50.	

License Condition 2.C.(3) requires NEDA to implement and maintain a fire protection program that complies with the requirements of 10 CFR 50.48(a) and 10 CFR 50.48(c). It is reinstated because it establishes requirements that relate to the ability to shutdown the plant safely in the event of a fire. This supports the reinstatement of the NFPA 805 fire protection program.

License Condition 2.C(4)	
Current Deleted	No change proposed.
Basis	
License Condition 2.C(4) is not reinstated because this information is contained in the licensing basis and is historical. The reinstated UFSAR Section 5.4.3.5, Inlet Nozzle Safe-End Replacement, describes in detail the modifications, testing and continuing surveillance of the modified safe ends installed on the primary recirculation system inlet piping. Any changes to the primary recirculation inlet piping will be made in accordance with plant procedures and evaluated against the licensing basis. This License Condition is historical and will not be reinstated.	

License Condition 2.C(5)	
Current Physical Protection NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to 10 CFR 72.212(b)(9) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: “Duane Arnold Energy Center Physical Security Plan,” submitted by letter dated June 3, 2021, as supplemented.	Proposed Physical Protection NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to 10 CFR 72.212(b)(9) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: “Duane Arnold Energy Center Physical Security Plan,” submitted by letter dated June 3, 2021, as supplemented. NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved Duane Arnold Energy Center/NextEra Energy Duane Arnold, LLC Cyber Security Plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Duane Arnold Energy Center/NextEra Energy Duane Arnold, LLC CSP was approved by License Amendment No. 278, as supplemented by changes approved by license Amendment No. 284 and Amendment 291.

Basis
This License Condition is proposed for reinstatement with subsequent approved changes. This license condition is reinstated to acknowledge that the plant will resume power operation as a utilization facility defined by 10 CFR Part 50. The first paragraph of this License Condition addresses the physical security plan for the DAEC site. This plan was updated and submitted by letter dated June 3, 2021. This plan remains in effect at the time of this submittal. As noted in Reference 2, an update to the site physical security plan will be submitted separately from this request. When approved, the first paragraph of this License Condition will be updated with the latest security plan information. The second paragraph addresses the cyber security plan for DAEC. This plan will be reinstated following appropriate reviews. This paragraph is required to address the reinstatement of the cyber security plan needed for power operation at DAEC. The NRC staff initially reviewed and approved DAEC's CSP plan and implementation schedule by Amendment No. 278, dated July 29, 2011 (ADAMS Accession No. ML111940224), which was concurrent with the incorporation of the CSP into the facility's current licensing basis. The NRC staff reviewed and approved current CSP implementation schedule in Amendment No. 284 (ADAMS Accession No. ML12321A266) and Amendment No. 291 (ADAMS Accession No. ML15169A261). Implementation of the DAEC CSP was completed by December 31, 2017.

License Condition 2.C(6)	
Current Deleted	No change proposed.
Basis	
License Condition 2.C(6) was deleted prior to the DAEC decommissioning effort and is not changed by this amendment request.	

License Condition 2.C(7)	
Current The Additional Conditions contained in Appendix B, as revised through Amendment No. 315, are hereby incorporated into this license. NextEra Energy Duane Arnold, LLC shall operate the facility in accordance with the Additional Conditions.	Proposed The Additional Conditions contained in Appendix B, as revised through Amendment No. **XXX**~~315~~, are hereby incorporated into this license. NextEra Energy Duane Arnold, LLC shall operate the facility in accordance with the Additional Conditions.
Basis	
The current amendment number is deleted and replaced with "XXX" which acts as a placeholder for the new amendment number associated with the approval of this LAR.	

License Condition 2.C(8)	
Current Deleted.	No change proposed.
Basis	
License Condition 2.C(8) is not reinstated because this action was completed. Amendment 251 (Reference 16) allowed the removal of a restriction concerning the reactor building crane from the UFSAR. Specifically, DAEC was permitted to revise the Updated Final Safety Analysis Report by deleting the notation that the NRC does not endorse the reactor building crane as	

single-failure-proof. The notation no longer exists in the UFSAR. This License Condition is historical and will not be reinstated.

License Condition 2.C(9)	
Current Deleted.	Proposed ~~Deleted.~~ Mitigation Strategy License Condition Develop and maintain strategies for addressing large fires and explosions and that include the following key areas: (a) Fire fighting response strategy with the following elements: 1. Pre-defined coordinated fire response strategy and guidance 2. Assessment of mutual aid fire fighting assets 3. Designated staging areas for equipment and materials 4. Command and control 5. Training of response personnel (b) Operations to mitigate fuel damage considering the following: 1. Protection and use of personnel assets 2. Communications 3. Minimizing fire spread 4. Procedures for implementing integrated fire response strategy 5. Identification of readily-available pre-staged equipment 6. Training on integrated fire response strategy 7. Spent fuel pool mitigation measures (c) Actions to minimize release to include consideration of: 1. Water spray scrubbing 2. Dose to onsite responders
Basis	
The license condition incorporates the requirements for Section B.5.b mitigation strategies of the Interim Compensatory Measures (ICM) Order EA-02-026 dated February 25, 2002 (ML020500299). Currently, 10 CFR 50.155(b)(2) applies to operating reactors and requires extensive damage mitigation guidelines to maintain or restore key capabilities under the circumstances associated with loss of large areas of the plant impacted by the event, due to explosions or fire. Note that	

the Mitigation of Beyond Design-Basis-Basis Events rulemaking (84 FR 39684) moved the requirements formerly in § 50.54(hh)(2) to § 50.155(b)(2). License Condition 2.C(9) is being reinstated to reflect the strategies and guidelines that are currently required by 10 CFR 50.155(b)(2).

License Condition 2.C(10)	
Current Deleted.	Proposed ~~Deleted.~~ The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.
Basis	
On June 20, 2006 (Reference 17), the NRC issued Order EA-06-137, “Order Requiring Compliance with Key Radiological Protection Mitigation Strategies,” to various operating nuclear power reactor licensees, including the Duane Arnold Energy Center (DAEC). It required those licensees to implement certain key radiological protection mitigation strategies for the purpose of allaying the effects of a loss-of-coolant accident for the reactor vessel. This Order was rescinded for DAEC in Reference 18 and this License Condition was subsequently deleted. With the return of DAEC to power operation, this Order will be reinstated and this License Condition is necessary.	

License Condition 2.C(11)	
Current Deleted.	Proposed ~~Deleted.~~ The information in the UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be incorporated into the UFSAR no later than the next scheduled update required by 10 CFR 50.71(e) following the issuance of this renewed operating license. Until this update is complete, the licensee may not make changes to the information in the supplement. Following incorporation into the UFSAR, the need for prior Commission approval of any changes will be governed by 10 CFR 50.59.
Basis	
This license condition is reinstated to support DAEC plans to pursue subsequent license renewal. Reinstating this license condition is consistent with recent precedent related to the Palisades restart (ML24191A422), which cited the restoration of a similar condition for maintaining consistency with subsequent license renewal industry precedent.	

License Condition 2.C(12)	
Current Deleted.	Proposed ~~Deleted.~~ The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), and as supplemented by Appendix A of NUREG-1955, "Safety Evaluation Report Related to the License Renewal of Duane Arnold Energy Center," dated November 2010, as supplemented by letter from the licensee to the NRC dated November 23, 2010, describes certain programs to be implemented and activities to be completed before the period of extended operation. a. NextEra Energy Duane Arnold, LLC shall implement those new programs and enhancements to existing programs no later than February 21, 2014. b. NextEra Energy Duane Arnold, LLC shall complete those activities no later than February 21, 2014. The licensee shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.
Basis	
This license condition is reinstated to support DAEC plans to pursue subsequent license renewal. Reinstating this license condition is consistent with recent precedent related to the Palisades restart (ML24191A422), which cited the restoration of a similar condition for maintaining consistency with subsequent license renewal industry precedent.	

License Condition 2.C(13)	
Current Deleted.	Proposed ~~Deleted.~~ The licensee shall implement the most recent staff-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as the method to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix H. Any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule which affects the time of withdrawal of any surveillance

	capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in a manner which maintains them in a condition which would support re-insertion into the reactor pressure vessel if necessary.
Basis	
Participation in the BWRVIP will be reinstated as part of the return to power operation. This License Condition ensures proper control of the required surveillance capsules and their withdrawal schedule.	

License Condition 2.D	
Current This license is effective as of the date of issuance and is effective until the Commission notifies the licensee in writing that the license is terminated.	Proposed This license is effective as of the date of issuance and ~~is effective until the Commission notifies the licensee in writing that the license is terminated~~ shall expire at midnight February 21, 2034.
Basis	
This License Condition currently conforms with 10 CFR 50.51, *Continuation of license*, in that the license authorizes ownership and possession by DAEC until the Commission notifies the licensee in writing that the license is terminated. While appropriate for a licensee that has permanently ceased operation, 10 CFR 50.51 requires that an operating reactor have a license issued for a fixed period of time. Therefore, this change is necessary to resume power operations.	

Appendix B Additional Conditions	
Current Amendment 223 / 275 DELETED	No change proposed.
Basis	
This Additional Condition was deleted in Amendment 315 (Reference 7). This License Condition was initially added upon implementation of Amendment 223 which transitioned the DAEC TS to the standard Technical Specification format of NUREG-1433. At that time, information that appeared in the DAEC custom TS, but was not part of the standard TS, was approved by the NRC for relocation to licensee-controlled documents. NEDA has completed the relocations allowed by Amendment 223 (Reference 19) and this relocation allowance is no longer needed. This License Condition is historical and will not be reinstated.	

Current Amendment 260 (1)/275 NextEra Energy Duane Arnold shall take all necessary steps to ensure that the external trust fund is established at the time of the closing of transfer of the	No change proposed.

license from Interstate Power and Light (IPL) to FPLE Duane Arnold is maintained in accordance with the requirements of the December 23, 2005 order approving the license transfer, NRC regulations, and consistent with the safety evaluation supporting the order. The trust agreement shall be in a form acceptable to the NRC.	
Basis	
This Additional Condition was revised in Amendment 311 (Reference 6). The revisions to the condition pertaining to decommissioning trust funding were to clarify current requirements and remove statements that are no longer relevant. This assessment remains valid and the Condition is not reinstated to the content that existed prior to Amendment 311. It remains in its current form.	

Current Amendment 260 (2) / 279 DELETED	No change proposed.
Basis	
This Additional Condition was deleted in Amendment 279. It was not affected by License Condition changes related to decommissioning. This License Condition will not be changed.	

Current Amendment 260 (3) DELETED	No change proposed.
Basis	
This Additional Condition was deleted in Amendment 311 (Reference 6). It addressed a support agreement established as part of the DAEC license transfer in 2005. As stated in the NRC's Safety Evaluation for the DAEC license transfer, dated December 23, 2005 (ADAMS Accession No. ML053420246), the purpose of the support agreement is to ensure the licensee has sufficient funds to cover operating costs. Moreover, the Support Agreement, which was provided as Enclosure 9 to the August 1, 2005 License Transfer Application (ADAMS Accession No. ML052160266), states that the agreement terminates when the plant ceases commercial operations. This Condition will not be reinstated at this time. Any new license condition regarding financial assurance for projected extended outage costs will be addressed separately from this request and prior to restart.	

Current N/A	Amendment Number XXX Additional Conditions The licensee is authorized to load fuel and perform low power testing, but may not exceed 5 percent of rated thermal power until, following the conduct of the exercise required by paragraph IV.F.2 of Appendix E to 10 CFR Part 50, the NRC notifies the licensee that the Federal Emergency Management Agency (FEMA): (1) has not identified any deficiencies in the state of offsite emergency preparedness; or (2) has informed the NRC that any offsite deficiencies have been corrected. Implementation With implementation of this Amendment
Basis	
This Condition is added to the Additional Conditions in Appendix B. It restricts power operation to 5% rated thermal power until certain required emergency exercises have been completed satisfactorily and FEMA requirements are satisfied. The proposed license condition is consistent with 10 CFR 50.47(d), which permits the NRC to authorize fuel load and low power testing or training (up to 5 percent of rated thermal power) pending completion of FEMA's final review and findings. The proposed DAEC Site Emergency Plan and the NRC's regulations in paragraph IV.F.2 of Appendix E to 10 CFR Part 50 require, among other things, that prior to resuming full power operations, DAEC must perform a "full participation" emergency preparedness exercise "which tests as much of the licensee, State, and local emergency plans as is reasonably achievable." FEMA's final approval of the State and county emergency plans will not be provided until the requirements for an exercise and a meeting with public participation are met in accordance with FEMA's regulations. Accordingly, a license condition is necessary to ensure that the full participation emergency exercise is completed, and any deficiencies identified by FEMA following the conduct of the exercise are corrected, prior to the resumption of full power operations.	

3.2.2 Proposed Changes to the DAEC Technical Specifications

Changes proposed to the TS are necessary to reinstate the TS that were removed or revised by license amendments 309, 311, and 315 (References 5, 6 and 7) due to docketing the 10 CFR 50.82 decommissioning certifications and removal of fuel from the spent fuel pool. All current TS are addressed below, even if no change is requested. No changes are proposed to the previously approved reinstated TS, except TS 5.3, "Staff Qualifications," as discussed below.

Prior to and since docketing of the 10 CFR 50.82(a)(1) certifications, there have been no non-conservative TS entered in the DAEC corrective action process. Therefore, the process described by Regulatory Guide 1.239, "Licensee Actions to Address Non-Conservative Technical Specifications," (ML20294A510) is not needed for this license amendment.

APPENDIX A Table of Contents	
Current Table of Contents 4.0 DESIGN FEATURES… 5.7 High Radiation Area	delete
Basis	
The Table of Contents (TOC) is proposed to be removed from the TS and placed under licensee control. Placing the TOC under licensee control eliminates the regulatory burden of submitting TOC pages for NRC review and allows timely administrative corrections and improvements to the TOC without NRC review and approval. The TOC does not meet the criteria specified in 10 CFR 50.36 requiring its inclusion within a plant's TS. The TOC references the page number of each Specification in the TS and does not contain any technical information required by 10 CFR 50.36. Since the TOC does not include information required to be in the TS by 10 CFR 50.36, inclusion of a TOC within the TS is optional. Removal of the TOC from the TS is an administrative change and is acceptable. The TS TOC will be maintained, revised, and distributed in accordance with administrative procedures. Holders of copies of the TS, including the NRC, will continue to receive periodic updates of the TOC pages.	

TS Section 1.0, Use and Application	
TS 1.0, Use and Application, provides information related to the use of the TS and the definitions contained within the TS. They are reinstated as they appeared prior to Amendment 309. There are no TS Bases associated with these TS.	
Proposed TS	**Basis for Change**
TS 1.1, Definitions See Attachment 2 for the complete TS.	Each Definition is used elsewhere in the proposed TS. The Definitions are added to Section 1.0 in alphabetical order.
TS 1.2, Logical Connectors See Attachment 2 for the complete TS.	These rules for properly using the TS are necessary for the reinstated TS.
TS 1.3, Completion Times See Attachment 2 for the complete TS.	These rules for properly using the TS are necessary for the reinstated TS.
TS 1.4, Frequency See Attachment 2 for the complete TS	These rules for properly using the TS are necessary for the reinstated TS.

TS Section 2.0 SAFETY LIMITS (SLs)
The fuel cladding, reactor pressure vessel and primary containment are the principal barriers to prevent the release of radioactive materials to the environs during operations. TS 2.1 establishes Safety Limits to protect the integrity of these barriers during normal plant operations and anticipated transients. TS 2.2 establishes action to be taken if the limits in TS 2.1 are violated. The corresponding TS Bases are also reinstated to reflect these changes.

Proposed TS	Basis for Change
TS 2.0, Safety Limits (SLs) See Attachment 2 for the complete TSs.	TS 2.1.1 establishes Safety Limits to protect the integrity of these barriers during normal plant operations and anticipated transients. The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations. TS 2.1.2 establishes the Safety Limit on reactor steam dome pressure which protects the RCS against overpressurization. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. TS 2.2 defines the action to take in the event of a violation of a SL as defined in TS 2.1. These TS are required to comply with 10CFR50.36(c)(1).

TS 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY	
TS 3.0, “Limiting Condition for Operation (LCO) Applicability,” establishes the general requirements applicable to all Specifications and applies at all times, unless otherwise stated. With the reinstatement of TSs, these general requirements are necessary to support use of the TSs. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS LCO 3.0.1 See Attachment 2 for the complete TS.	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met.
TS LCO 3.0.2 See Attachment 2 for the complete TS.	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met.
TS LCO 3.0.3 See Attachment 2 for the complete TS	LCO 3.0.3 provides the actions that must be implemented when an LCO is not met. It is only applicable in MODES 1 through 3.

Proposed TS	Basis for Change
TS LCO 3.0.4 See Attachment 2 for the complete TS.	LCO 3.0.4 provides limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met.
TS LCO 3.0.5 See Attachment 2 for the complete TS.	LCO 3.0.5 provides the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS.
TS LCO 3.0.6 See Attachment 2 for the complete TS.	LCO 3.0.6 addresses the actions required for a supported system when the support system LCO is not met.
TS LCO 3.0.7 See Attachment 2 for the complete TS.	LCO 3.0.7 allows certain LCO exceptions when special tests are required to be performed at various times over the life of the plant.
TS LCO 3.0.8 See Attachment 2 for the complete TS.	LCO 3.0.8 addresses the actions required when one or more required snubbers are unable to perform their associated support function(s).
TS LCO 3.0.9 See Attachment 2 for the complete TS.	LCO 3.0.9 addresses the actions required when one or more required barriers are unable to perform their related support function(s).

TS 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY	
TS Section 3.0 contains the general requirements applicable to all Specifications and applies at all times, unless otherwise stated. With the reinstatement of TSs, these general requirements are necessary to support use of the TSs. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS SR 3.0.1 See Attachment 2 for the complete TS	SR 3.0.1 establishes the requirement that SRs must be met during MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs.
TS SR 3.0.2 See Attachment 2 for the complete TS.	SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.
TS SR 3.0.3 See Attachment 2 for the complete TS.	SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits

Proposed TS	Basis for Change
	when a Surveillance has not been completed within the specified Frequency..
TS SR 3.0.4 See Attachment 2 for the complete TS.	SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

TS SECTION 3.1 REACTIVITY CONTROL SYSTEMS	
TS Section 3.1, “Reactivity Control Systems,” contains LCOs that provide for appropriate control of process variables, design features, or operating restrictions required to protect the integrity of fission product barriers. TS Section 3.1 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.1.1, SHUTDOWN MARGIN (SDM) See Attachment 2 for the complete TS.	TS 3.1.1 ensures the SDM requirements are specified to ensure: a. The reactor can be made subcritical from all operating conditions and transients and Design Basis Accidents; b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits; and c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition. The SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2).
TS 3.1.2, Reactivity Anomalies See Attachment 2 for the complete TS	The continual confirmation of core reactivity is necessary to ensure that the Design Basis Accident (DBA) and transient safety analyses remain valid. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations in assuring the reactor can be brought safely to cold, subcritical conditions. Reactivity anomalies satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.1.3, Control Rod OPERABILITY See Attachment 2 for the complete TS.	Control rods are components of the Control Rod Drive System, which is the primary reactivity control system for the reactor. This Specification, along with LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators," ensure that the performance of the control rods in the event of a Design Basis Accident or transient meets the assumptions used in the safety analyses. Control rod OPERABILITY satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.1.4, Control Rod Scram Times See Attachment 2 for the complete TS.	The scram function of the Control Rod Drive System controls reactivity changes during Abnormal Operational Transients and Design Basis Accidents to ensure that specified acceptable fuel design limits are not exceeded. Control rod scram times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.1.5, Control Rod Scram Accumulators See Attachment 2 for the complete TS.	The control rod scram accumulators are part of the Control Rod Drive System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a control rod at any reactor vessel pressure. Control Rod Scram Accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.1.6, Rod Pattern Control See Attachment 2 for the complete TS.	This Specification assures that the control rod patterns are consistent with the assumptions of the Control Rod Drop Accident analyses. Rod Pattern Control satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.1.7, Standby Liquid Control (SLC) System See Attachment 2 for the complete TS.	The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive, xenon

Proposed TS	Basis for Change
	free state without taking credit for control rod movement. In addition, the SLC System is relied upon to satisfy the requirements of 10 CFR 50.62 on Anticipated Transient Without Scram. The SLC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) because operating experience and probabilistic risk assessments have shown the SLC System to be important to public health and safety. Thus, it is reinstated in the Technical Specifications.
TS 3.1.8, Scram Discharge Volume (SDV) Vent and Drain Valves See Attachment 2 for the complete TS.	The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. SDV Vent and Drain Valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.2 POWER DISTRIBUTION LIMITS	
TS Section 3.2, “Power Distribution Limits,” contains LCOs that provide for appropriate control of process variables, design features, or operating restrictions required to protect the integrity of fission product barriers. TS Section 3.2 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.2.1, AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) See Attachment 2 for the complete TS.	Limits on the APLHGR are specified to ensure that the fuel design are not exceeded during Abnormal Operational Transients; and, also to assure that the Peak Cladding Temperature during the postulated design basis Loss of Coolant Accident does not exceed the limits specified in 10 CFR 50.46. The APLHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii)

Proposed TS	Basis for Change
TS 3.2.2, MINIMUN CRITICAL POWER RATIO (MCPR) See Attachment 2 for the complete TS.	The operating limit MCPR is established to ensure that no fuel damage results during Abnormal Operational Transients. The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.3 INSTRUMENTATION	
TS Section 3.3 contains operability requirements for sensing and control instrumentation required for safe operation of the facility. TS Section 3.3 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation See Attachment 2 for the complete TS.	The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limits, to preserve the integrity of the fuel cladding and the Reactor Coolant Pressure Boundary (RCPB), minimize the energy that must be absorbed following a Loss of Coolant Accident (LOCA), and prevent inadvertent criticality. This can be accomplished either automatically or manually. RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.
TS 3.3.1.2, Source Range Monitor (SRM) Instrumentation See Attachment 2 for the complete TS.	The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The SRMs have no safety function and are not assumed to function during any UFSAR design basis accident or transient analysis. However, the SRMs provide the only on-scale monitoring of neutron flux levels during startup and refueling. Therefore, they are retained in Technical Specifications.

Proposed TS	Basis for Change
TS 3.3.2.1, Control Rod Block Instrumentation See Attachment 2 for the complete TS.	Control rod block instrumentation includes channel sensors, logic circuitry, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. The Rod Block instrumentation satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
TS 3.3.3.1, Post Accident Monitoring (PAM) Instrumentation See Attachment 2 for the complete TS.	The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to determine that the actions automatically initiated by the Engineered Safety Features equipment have successfully accomplished their safety functions for Design Basis Events. Category I, non-Type A, instrumentation is retained in Technical Specifications (TS) because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I instruments are important for reducing public risk and satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.3.2, Remote Shutdown System See Attachment 2 for the complete TS.	The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3. The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it has been retained in the Technical Specifications (TS). The Remote Shutdown System satisfies criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.4.1, End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation See Attachment 2 for the complete TS.	The EOC-RPT instrumentation initiates a Recirculation Pump Trip to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to

Proposed TS	Basis for Change
	provide additional margin to core thermal MCPR Safety Limits. EOC-RPT instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.4.2, Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation See Attachment 2 for the complete TS.	The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. The ATWS-RPT is not assumed to function during or after a design basis accident. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which a scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation is included as required by Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.5.1, Emergency Core Cooling System (ECCS) Instrumentation See Attachment 2 for the complete TS.	The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that the fuel is adequately cooled in the event of a design basis accident or transient. The ECCS instrumentation actuates Core Spray, Low Pressure Coolant Injection, High Pressure Coolant Injection, Automatic Depressurization System, and the Diesel Generators. ECCS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.5.2, Reactor Pressure Vessel (RPV) Water Inventory Control Instrumentation See Attachment 2 for the complete TS.	The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control,” and the definition of DRAIN TIME. There are functions that are required for manual initiation or operation of the ECCS injection/spray subsystem required to be OPERABLE and other functions that support automatic isolation of Residual Heat Removal subsystem and Reactor Water Cleanup system penetration flow path(s) on low RPV water level.

Proposed TS	Basis for Change
	Operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.5.3, Reactor Core Isolation Cooling (RCIC) System Instrumentation See Attachment 2 for the complete TS.	The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is unavailable, such that initiation of the low pressure Emergency Core Cooling Systems pumps does not occur. Based on its contribution to the reduction of overall plant risk the system, and therefore its instrumentation meets Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.6.1, Primary Containment Isolation Instrumentation See Attachment 2 for the complete TS.	The primary containment isolation instrumentation automatically initiates closure of appropriate Primary Containment Isolation Valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents. Primary Containment Isolation Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.6.2, Secondary Containment Isolation Instrumentation See Attachment 2 for the complete TS.	The secondary containment isolation instrumentation automatically initiates closure of appropriate Secondary Containment Isolation Valves and/or Dampers and starts the Standby Gas Treatment System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents. The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.3.6.3, Low-Low Set (LLS) Instrumentation See Attachment 2 for the complete TS.	The LLS logic and instrumentation is designed to mitigate the effects of postulated thrust loads on the Safety Relief Valve (SRV) discharge lines by preventing subsequent actuations with an elevated water leg in the SRV discharge line. It also mitigates the effects of postulated pressure loads on the torus shell or suppression pool by preventing multiple actuations in rapid succession of the SRVs subsequent to their initial actuation. The LLS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.7.1, Standby Filter Unit (SFU) System Instrumentation See Attachment 2 for the complete TS.	The SFU System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. SFU System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.8.1, Loss of Power (LOP) Instrumentation See Attachment 2 for the complete TS.	The LOP instrumentation monitors the 4.16 kv emergency bus voltages and the Startup and Standby Transformer secondary winding voltages. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite Diesel Generator power sources. The LOP instrumentation also serves to provide protection for the ESF from damage that could occur due to prolonged degraded voltage conditions on the grid. The LOP instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.3.8.2, Reactor Protection System (RPS) Electric Power Monitoring See Attachment 2 for the complete TS.	RPS Electric Power Monitoring System is provided to isolate the RPS bus from the Motor Generator set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions and forms an important part of the primary success path of the essential safety circuits.

Proposed TS	Basis for Change
	RPS electric power monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

TS 3.4 REACTOR COOLANT SYSTEM (RCS)	
TS 3.4, “Reactor Coolant System (RCS),” contains LCOs that provide for appropriate control of process variables, design features, or operating restrictions needed for appropriate functional capability of RCS equipment required for safe operation of the facility. TS Section 3.4 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.4.1, Recirculation Loops Operating See Attachment 2 for the complete TS.	The Reactor Coolant Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.2, Jet Pumps See Attachment 2 for the complete TS.	The jet pumps are part of the Reactor Coolant Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. Jet Pumps satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.3, Safety Relief Valves (SRVs) and Safety Valves (SVs) See Attachment 2 for the complete TS.	The ASME Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of SRVs and SVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the Reactor Coolant Pressure Boundary. SRVs and SVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.4.4, RCS Operational LEAKAGE See Attachment 2 for the complete TS.	The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the Reactor Coolant Pressure Boundary (RCPB). During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. RCS Operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.5, RCS Leakage Detection Instrumentation See Attachment 2 for the complete TS.	Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.6, RCS Specific Activity See Attachment 2 for the complete TS.	Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 50.67. RCS Specific Activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.7, Residual Heat Removal (RHR) Shutdown Cooling System – Hot Shutdown See Attachment 2 for the complete TS.	Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to $\leq$ 212°F. This decay heat is removed in preparation for performing Refueling or Cold

Proposed TS	Basis for Change
	Shutdown maintenance operations, or for keeping the reactor in the Hot Shutdown condition. Decay heat removal is an important function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.8, Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown See Attachment 2 for the complete TS.	Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant $\leq$ 212°F. This decay heat is removed in preparation for performing Refueling maintenance operations or for keeping the reactor in the Cold Shutdown condition. Decay heat removal is an important function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.4.9, RCS Pressure and Temperature (P/T) Limits See Attachment 2 for the complete TS.	The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the Reactor Coolant Pressure Boundary. The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel. RCS P/T Limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii)
TS 3.4.10, Reactor Steam Dome Pressure See Attachment 2 for the complete TS.	The reactor steam dome pressure is an assumed initial condition of design basis accidents and transients and is conservative to the value used in the determination of compliance with reactor pressure vessel overpressure protection criteria. Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM
TS 3.5, “Emergency Core Cooling Systems (ECCS), RPV Water Inventory Control, and Reactor Core Isolation Cooling (RCIC),” contains LCOs that provide for appropriate control of process variables, design features, or operating restrictions needed for appropriate functional capability of RCS equipment required for safe operation of the facility. TS Section 3.5 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.

Proposed TS	Basis for Change
TS 3.5.1, ECCS — Operating See Attachment 2 for the complete TS.	The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a Loss of Coolant Accident. The ECCS network consists of the High Pressure Coolant Injection System, the Core Spray System, the Low Pressure Coolant Injection mode of the Residual Heat Removal System, and the Automatic Depressurization System. The suppression pool provides the required source of water for the ECCS. The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.5.2, Reactor Pressure Vessel (RPV) Water Inventory Control See Attachment 2 for the complete TS.	The RPV water level must be controlled in Modes 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by TS 2.1.1.3. Operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.5.3, RCIC System See Attachment 2 for the complete TS.	The RCIC System is designed to operate either automatically or manually following Reactor Pressure Vessel (RPV) isolation accompanied by a loss of coolant flow from the Feedwater System to provide adequate core cooling and control of the RPV water level. The RCIC System is not an ECCS System, although the RCIC System operation is credited during Loss of Feedwater events. Based on its contribution to the reduction of overall plant risk, however, the system satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.6 CONTAINMENT SYSTEMS
TS Section 3.6 contains requirements that assure the integrity of the primary and secondary containment, depressurization and cooling systems, and containment atmosphere. TS Section 3.6 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.

Proposed TS	Basis for Change
TS 3.6.1.1, Primary Containment See Attachment 2 for the complete TS.	The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Loss of Coolant Accident and to confine the postulated release of radioactive material. Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.1.2, Primary Containment Air Lock See Attachment 2 for the complete TS.	One double door primary containment air lock has been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents. The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
TS 3.6.1.3, Primary Containment Isolation Valves (PCIVs) See Attachment 2 for the complete TS.	The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary 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 DBA. PCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.6.1.4, Drywell Air Temperature See Attachment 2 for the complete TS.	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents. The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.1.5, Low-Low Set (LLS) Valves See Attachment 2 for the complete TS.	The LLS relief mode functions to ensure that the containment design basis of one SRV operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of SRVs (following the initial opening), and the corresponding higher loads, are avoided. The LLS function justifies the primary containment analysis assumption that simultaneous SRV openings occur only on the initial actuation for Limiting Transients. LLS valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.1.6, Reactor Building-to-Suppression Chamber Vacuum Breakers See Attachment 2 for the complete TS.	The function of the two reactor building-to-suppression chamber vacuum breaker assemblies is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breaker assemblies and through the suppression-chamber-to-drywell vacuum breakers. The reactor building-to-suppression chamber vacuum breaker assemblies satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.6.1.7, Suppression Chamber-to-Drywell Vacuum Breakers See Attachment 2 for the complete TS.	The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. Suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.2.1, Suppression Pool Average Temperature See Attachment 2 for the complete TS.	The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges or from Design Basis Accidents. A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. Suppression Pool Average Temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.2.2, Suppression Pool Water Level See Attachment 2 for the complete TS.	The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from Safety/Relief Valve (SRV) discharges or from a Design Basis Accident. If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the SRV T-quenchers, vent system downcomer pipes, or HPCI and RCIC turbine exhaust lines. Suppression Pool Water Level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.2.3, Residual Heat Removal (RHR) Suppression Pool Cooling See Attachment 2 for the complete TS	Following a Design Basis Accident, the RHR Suppression Pool Cooling System can be used to remove heat from the suppression pool. The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.6.2.4, Residual Heat Removal (RHR) Suppression Pool Spray See Attachment 2 for the complete TS.	Steam blowdown from a DBA can bypass the suppression pool and end up in the suppression chamber airspace as a result of the allowable leakage between the Drywell and Suppression Chamber. Although not required by the accident analysis to ensure that the suppression chamber remains within the analyzed design pressure and temperature limits, condensing the steam in the suppression chamber airspace reduces the long-term pressure response in the primary containment. This function was found to satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
TS 3.6.3.1, Containment Atmosphere Dilution (CAD) System	Previously deleted by Amendment 265. This TS will not be reinstated, but a placeholder page is provided.
TS 3.6.3.2, Primary Containment Oxygen Concentration See Attachment 2 for the complete TS.	Evaluations assume that the primary containment is inerted when an event with significant core damage occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of degraded core conditions is not likely to produce combustible gas mixtures in the primary containment. Primary Containment Oxygen Concentration satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.4.1, Secondary Containment See Attachment 2 for the complete TS.	The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident. Secondary Containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.6.4.2, Secondary Containment Isolation Valves/Dampers (SCIV/Ds) See Attachment 2 for the complete TS.	The function of the SCIV/Ds, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents. SCIV/Ds satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.6.4.3, Standby Gas Treatment (SBGT) System See Attachment 2 for the complete TS.	The function of the SBGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident are filtered and adsorbed prior to exhausting to the environment. The SBGT System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.7 PLANT SYSTEMS
TS 3.7, “Plant Systems,” contains LCOs that provide for appropriate control of process variables, design features, or operating restrictions needed for appropriate functional capability of equipment required for safe operation of the facility. TS Section 3.7 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.

Proposed TS	Basis for Change
TS 3.7.1, Residual Heat Removal Service Water (RHRSW) System See Attachment 2 for the complete TS.	The RHRSW System is designed to provide cooling water for the Residual Heat Removal System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident or transient. The RHRSW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.2, River Water Supply (RWS) System and Ultimate Heat Sink (UHS) See Attachment 2 for the complete TS.	The RWS System is designed to provide cooling water for the Emergency Service Water and Residual Heat Removal Service Water Systems, which provide required support for various systems required for a safe reactor shutdown following a Design Basis Accident or transient. The RWS System also provides water to the Circulating Water System to make up for cooling tower evaporative losses, as required, during normal operation. The RWS System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.7.3, Emergency Service Water System (ESW) See Attachment 2 for the complete TS.	The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the Diesel Generators, room coolers for Emergency Core Cooling System equipment, Control Building Chillers, and various minor heat loads required for a safe reactor shutdown following a Design Basis Accident or transient. The ESW System also provides cooling to unit components, as desired during normal operation. The ESW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.4, Standby Filter Unit (SFU) System See Attachment 2 for the complete TS.	The SFU System provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals or smoke. The SFU System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.5, Control Building Chiller (CBC) System See Attachment 2 for the complete TS.	The CBC System provides temperature control for the control building HVAC system under both normal and accident conditions. The CBC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.6, Main Condenser Offgas See Attachment 2 for the complete TS.	The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.7, Main Turbine Bypass System See Attachment 2 for the complete TS.	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.7.8, Spent Fuel Pool Water Level See Attachment 2 for the complete TS.	The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident. The spent fuel storage pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.7.9, Control Building/Standby Gas Treatment Instrument Air System See Attachment 2 for the complete TS.	The CB/SBGT Instrument Air System is designed to provide compressed air to support systems and components that function to limit fission product release and control the environment from which the unit can be safely operated following a Design Basis Accident. The CB/SBGT Instrument Air System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

TS SECTION 3.8 ELECTRICAL POWER SYSTEMS

TS 3.8, “Electrical Power Systems,” contains LCOs that provide for appropriate functional capability of plant electrical equipment required for safe operation of the facility.

TS Section 3.8 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.

Proposed TS	Basis for Change
TS 3.8.1, AC Sources – Operating See Attachment 2 for the complete TS.	The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.8.2, AC Sources – Shutdown See Attachment 2 for the complete TS.	In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (Diesel Generator) power. The AC Sources – Shutdown satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

TS 3.8.3, Diesel Fuel Oil, Lube Oil, and Starting Air See Attachment 2 for the complete TS.	The Diesel Generators (DGs) are provided with a storage tank having sufficient fuel oil capacity to operate one DG for a period of 7 days while the DG is supplying maximum post Loss of Coolant Accident load demand. The DG Lubrication System is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. Since diesel fuel oil, lube oil, and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.8.4, DC Sources – Operating See Attachment 2 for the complete TS.	The DC Electrical Power System provides the AC Emergency Power System with control power. It also provides both motive and control power to selected safety related equipment. The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.8.5, DC Sources – Shutdown See Attachment 2 for the complete TS.	The DC Electrical Power System provides the AC Emergency Power System with control power. It also provides both motive and control power to selected safety related equipment. The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.8.6, Battery Cell Parameters See Attachment 2 for the complete TS.	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems batteries. Since battery cell parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.8.7, Distribution Systems – Operating See Attachment 2 for the complete TS.	The AC and DC Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The AC and DC Electrical Power Distribution System satisfies Criterion 3 of 10 CFR

	50.36(c)(2)(ii).
TS 3.8.8, Distribution Systems – Shutdown See Attachment 2 for the complete TS.	The AC and DC Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.9 REFUELING OPERATIONS	
TS 3.9, “Refueling Operations,” contains LCOs that provide for appropriate functional capability of parameters and equipment within containment that are required for mitigation of design basis accidents during refueling operations. TS Section 3.9 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.9.1 – Refueling Equipment Interlocks See Attachment 2 for the complete TS.	Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to serve as a backup to procedural core reactivity controls to prevent the reactor from achieving criticality during refueling. Refueling Equipment Interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.2, Refuel Position One-Rod-Out Interlock See Attachment 2 for the complete TS.	The refuel position one-rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn. The Refuel Position One-Rod-Out Interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.3, Control Rod Position See Attachment 2 for the complete TS.	The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions. All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during

Proposed TS	Basis for Change
	refueling. Control Rod Position satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.4, Control Rod Position Indication See Attachment 2 for the complete TS.	The full-in position indication for each control rod provides necessary information to the refueling interlocks to prevent inadvertent criticalities during refueling operations. Control Rod Position Indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.5 – Control Rod OPERABILITY – Refueling See Attachment 2 for the complete TS.	Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operations. Control Rod OPERABILITY - Refueling satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.6, Reactor Pressure Vessel (RPV) Water Level See Attachment 2 for the complete TS.	The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level in the reactor vessel cavity to retain iodine fission product activity in the water in the event of a fuel handling accident. RPV Water Level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
TS 3.9.7, Residual Heat Removal (RHR) – High Water Level See Attachment 2 for the complete TS.	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant. With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant. RHR – High Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Proposed TS	Basis for Change
TS 3.9.8, Residual Heat Removal (RHR) – Low Water Level See Attachment 2 for the complete TS.	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant. With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant. RHR – Low Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

TS SECTION 3.10 SPECIAL OPERATIONS	
TS 3.10 “Special Operations,” contains LCOs that provide for appropriate functional capability of parameters and equipment required for mitigation of design basis accidents during specific operating scenarios. TS Section 3.10 is proposed for reinstatement in its entirety. The corresponding TS Bases are also reinstated to reflect these changes.	
Proposed TS	**Basis for Change**
TS 3.10.1, System Leakage and Hydrostatic Testing Operation See Attachment 2 for the complete TS.	The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the Reactor Pressure Vessel require the pressure testing at temperatures ≥ 212°F (normally corresponding to MODE 3) or to allow completing these reactor pressure tests when the initial conditions do not require temperatures > 212ºF. Furthermore, the purpose is to allow continued performance of control rod scram time testing required by SR 3.1.4.1 or SR 3.1.4.2 if reactor coolant temperatures exceed 212ºF when the control rod scram time testing is initiated in conjunction with a system leakage or hydrostatic test. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.

Proposed TS	Basis for Change
TS 3.10.2, Reactor Mode Switch Interlock Testing See Attachment 2 for the complete TS.	The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
TS 3.10.3, Single Control Rod Withdrawal – Hot Shutdown See Attachment 2 for the complete TS.	The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in Hot Shutdown, by imposing certain restrictions. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
TS 3.10.4, Single Control Rod Withdrawal – Cold Shutdown See Attachment 2 for the complete TS.	The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in Cold Shutdown, by imposing certain restrictions. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.

Proposed TS	Basis for Change
TS 3.10.5, Single Control Rod Drive (CRD) Removal – Refueling See Attachment 2 for the complete TS.	The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
TS 3.10.6 – Multiple Control Rod Withdrawal – Refueling See Attachment 2 for the complete TS.	The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawals during refueling by imposing certain administrative controls. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
TS 3.10.7, Control Rod Testing – Operating See Attachment 2 for the complete TS.	The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
TS 3.10.8, SHUTDOWN MARGIN (SDM) Test – Refueling See Attachment 2 for the complete TS.	The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the Reactor Pressure Vessel head is either not in place or the head bolts are not fully tensioned. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.

<table>
<tr><th colspan="2">TS Section 4.0 DESIGN FEATURES</th></tr>
<tr><td colspan="2">TS 4.0 contains a brief description of the DAEC location, description and requirements for the DAEC reactor core and a description of and requirements for fuel storage at DAEC.

There are no TS Bases associated with TS Section 4.0.</td></tr>
<tr><th colspan="2">TS 4.1 – Site Location</th></tr>
<tr><th>Current TS</th><th>Proposed TS</th></tr>
<tr><td>4.1 Site Location
The plant site, which consists of approximately 500 acres, is adjacent to the Cedar River approximately 2.5 miles northeast of the Village of Palo, Iowa. The boundary of the exclusion area defined in 10 CFR 100 is delineated by the property lines. The distance to the outer boundary of the low population zone is 6 miles. The plan of the site is shown on DSAR Figures 1-1 and 1-2.</td><td>4.1 Site Location
The plant site, which consists of approximately 500 acres, is adjacent to the Cedar River approximately 2.5 miles northeast of the Village of Palo, Iowa. Distance from the reactor centerline to the nearest site boundary is approximately 2000 ft. The boundary of the exclusion area defined in 10 CFR 100 is delineated by the property lines. The distance to the outer boundary of the low population zone is 6 miles. The plan of the site is shown on ~~DSAR~~ UFSAR Figures ~~1-1 and 1-2~~ 1.2-1 and 1.2-2.</td></tr>
<tr><td colspan="2">Basis</td></tr>
<tr><td colspan="2">With the resumption of power operation, the reactor centerline location within the site boundary is consequential as it is related to various dose analyses. Therefore, TS 4.1 will add this reference to the DAEC reactor centerline distance. Additionally, the UFSAR is described in place of the DSAR. Therefore, Figure references are changed to reflect their location in the UFSAR.</td></tr>
<tr><th colspan="2">TS 4.2 – Reactor Core</th></tr>
<tr><th>Current TS</th><th>Proposed TS</th></tr>
<tr><td>4.2
Deleted</td><td>4.2 Reactor Core
~~Deleted~~
4.2.1 Fuel Assemblies…
4.2.2 Control Rod Assemblies…

See Attachment 2 for the complete TSs.</td></tr>
<tr><td colspan="2">Basis</td></tr>
<tr><td colspan="2">TS 4.2 provides requirements for reactor fuel assemblies and control rods in the reactor core. In an operating plant, fuel assemblies and control rod requirements for the core are necessary. Therefore, this TS will be reinstated.</td></tr>
</table>

TS 4.3 – Fuel Storage	
Current TS	**Proposed TS**
4.3 Fuel Storage Spent Fuel shall not be stored in the spent fuel pool.	4.3 Fuel Storage ~~Spent Fuel shall not be stored in the spent fuel pool.~~ 4.3.1 Criticality… 4.3.2 Drainage… 4.3.3 Capacity… See Attachment 2 for the complete TSs.
Basis	
TS 4.3 contains a description of, and requirements for, fuel storage at DAEC. TS 4.3.1 provides requirements for the fuel racks for spent fuel and new fuel assemblies. TS 4.3.2 ensures SFP water level is maintained to prevent inadvertent draining of the SFP. TS 4.3.3 contains a description of and requirements for capacity of the spent fuel storage pool.	

TS Section 5.0 ADMINISTRATIVE CONTROLS	
TS Section 5.0 establishes the requirements associated with site personnel responsibilities, the site organization, staffing, training, procedures, programs, reporting requirements, and high radiation areas. This section is proposed to be reinstated since these administrative requirements are needed for power operation of DAEC. Sections are reinstated in their entirety as shown in Attachment 2, except Section 5.3, which is modified as shown below. There are no TS Bases associated with Section 5.0.	
Proposed TS	**Basis for Change**
TS 5.1 Responsibilities See Attachment 2 for the complete TS.	TS 5.1 Describes the responsibilities for the plant manager and the shift manager. The TS describes the necessary delegation of authority for these positions.
TS 5.2 Onsite and Offsite Organizations See Attachment 2 for the complete TS.	Onsite and offsite organizations are established for unit operation and corporate management, respectively. Lines of authority, responsibility, and communication are defined and established throughout highest management levels. Additionally, shift crew composition is established and meets the requirements in 10 CFR 50.54(m).

Proposed TS	Basis for Change
TS 5.3 Unit Staff Qualifications 5.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications referenced for comparable positions, as specified in the Florida Power and Light Company and NextEra Energy Quality Assurance Topical Report (FPL-1).	The original TS Section 5.3.1 provided the qualifications for certain staff positions. This section was relocated to the DQAP in Amendment 315 (Reference 10). Those same qualification requirements are also contained in Appendix G of the transitional QATR (FPL-3) submitted on September 5, 2025 (ML25258A029). Additionally, they are contained in the fleet QATR that DAEC will transition to upon entering an operating condition. Therefore, the reference to FPL-1 as the QATR is appropriate as it is the QATR that will be effective when DAEC transitions to operation. This LAR does not change any staff ANSI qualification requirements for DAEC and is only an administrative TS change.
TS 5.4 Procedures See Attachment 2 for the complete TSs.	Written procedures shall be established, implemented, and maintained for certain activities as defined by this TS.
TS 5.5 Programs and Manuals See Attachment 2 for the complete TSs.	The following programs and manuals will be reinstated. 5.5.1 Offsite Dose Assessment Manual (ODAM) The ODAM contains the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and The ODAM shall also contain the radioactive effluent controls and radiological environmental monitoring activities. 5.5.2 Primary Coolant Sources Outside Containment This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly

Proposed TS	Basis for Change
	radioactive fluids during a serious transient or accident to levels as low as practicable. 5.5.3 [previously deleted] 5.5.4 Radioactive Effluent Controls Program This program, conforming to 10 CFR 50.36a, provides for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. 5.5.5 Component Cyclic or Transient Limit This program provides controls to track the cyclic and transient occurrences to ensure that components are maintained within the design limits as described in the UFSAR. 5.5.6 [previously deleted] 5.5.7 Ventilation Filter Testing Program (VFTP) A program is established to implement the required testing of Engineered Safety Feature filter ventilation systems. 5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program This program provides controls for potentially explosive gas mixtures contained in the Offgas System downstream of the recombiners and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. 5.5.9 Diesel Fuel Oil Testing Program A diesel fuel oil testing program is established to implement required testing of both new fuel oil and stored fuel oil. 5.5.10 Technical Specifications (TS) Bases Control Program This program provides a means for processing changes to the Bases of these Technical Specifications. 5.5.11 Safety Function Determination Program (SFDP)

Proposed TS	Basis for Change
	This program ensures a loss of safety function is detected and appropriate actions taken. 5.5.12 Primary Containment Leakage Rate Testing Program A program is established to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. 5.5.13 Control Building Envelope Habitability Program A Control Building Envelope (CBE) Habitability Program is established to ensure that CBE habitability is maintained such that, with an OPERABLE Standby Filter Unit System, CBE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. 5.5.14 Surveillance Frequency Control Program The program ensures that Surveillance Requirements specified in the TS are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met. 5.5.15 Spent Fuel Pool Neutron Absorber Monitoring Program This program provides routine monitoring and actions to ensure that the condition of Boral in the spent fuel pool racks is appropriately monitored.
<u>TS 5.6 Reporting Requirements</u> See Attachment 1 for the marked-up TSs.	Note that TS 5.6.3, Radioactive Material Release Report exists in the current TS and is retained. The following reporting requirements will be reinstated. 5.6.1 [previously deleted]

Proposed TS	Basis for Change
	5.6.2 Annual Radiological Environmental Operating Report The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. 5.6.3 Radioactive Material Release Report This reporting requirement exists in the current TS and is retained without change. 5.6.4 [previously deleted] 5.6.5 CORE OPERATING LIMITS REPORT (COLR) Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR. 5.6.6 PAM Describes the reporting requirement when a report required by Condition B or F of LCO 3.3.3.1 must be submitted to the NRC. 5.6.7 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR.
<u>TS 5.7 High Radiation Area</u> See Attachment 2 for the complete TS.	This TS is currently contained in the existing TS and is included here because an editorial change was made to the pages in this section. The footer for this section currently contains the phrase “AMENDMENT” This phrase is modified to “AMENDMENT NO.” to match the rest of the TS.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met.

4.1.1 10 CFR 50.36 Technical Specifications

In 10 CFR 50.36, the Commission established its regulatory requirements related to the content of the TS.

In accordance with 10 CFR 50.36, TS are required to include items in the following five categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) LCOs; (3) SRs; (4) design features; and (5) administrative controls. However, the rule does not specify the particular requirements to be included in a plant's TS.

This proposed amendment reinstates the portions of the previous DAEC TS that are applicable to a power operation plant. It proposes changes to every section of the TS listed in 10 CFR 50.36(c)(1) through 10 CFR 50.36(c)(5). The safety limits and limiting safety system settings are reinstated in Section 2.0 as described previously. The LCOs and SRs are reinstated to support plant power operation. The four criteria listed in 10 CFR 50.36(c)(2) are used to determine which structures, systems and components are required to be in the TS. As described in the previous sections, each TS in Sections 3.1 through 3.9 list the 10 CFR 50.36(c)(2) criterion that applies to a particular TS. The design features are revised to support the receipt and handling of new fuel for power operations. The administrative controls are modified and added to support the necessary programs and reports for an operating reactor. Therefore, the proposed DAEC TS meet the criteria of 10 CFR 50.36 for an operating reactor.

4.1.2 10 CFR 50.51, Continuation of License

10 CFR 50.51, Continuation of License 10 CFR 50.51 states, in part: "(a) Each license will be issued for a fixed period of time to be specified in the license…." DAEC complies with this regulation by the reinstatement of the RFOL expiration date in the RFOL.

4.2 Precedent

Precedent for reauthorization of power operation after docketing the 10 CFR 50.82(a)(1) certification and before reaching the renewed facility license expiration date has been issued. Palisades Nuclear Plant has received reinstatement of TS necessary to resume power operation, as described in the following:

- USNRC letter to Holtec International, LLC, "Issuance of Amendment No. 276 re: Amendment Request to Revise Renewed Facility Operating License and

Permanently Defueled Technical Specifications to Support Resumption of Power Operations" dated July 24, 2025 (ADAMS Accession No. ML25157A127)

- USNRC letter to Holtec International, LLC, "Issuance of Amendment No. 277 re: Amendment Request to Revise Selected Permanently Defueled Technical Specifications Administrative Controls to Support Resumption of Power Operations," dated July 24, 2025 (ADAMS Accession No. ML25157A107)

Precedent for the removal of the Table of Contents from the Technical Specifications is found in the following approval of a request for Southern Nuclear Company in 2021:

- USNRC letter to Southern Nuclear Operating Co., Inc, “Issuance of Amendments Regarding Removal of Table of Contents from the Technical Specifications,” dated September 29, 2021 (ADAMS Accession No. ML21232A149)

Precedents for relocation of staff qualification requirements from TS 5.3 to the QATR are found in several approvals, such as the following. Note that the approval for the Florida Power and Light and Nextera Energy fleet is the same approval as requested for DAEC.

- USNRC letter to Florida Power and Light, “Issuance of Amendment Nos. 278, 80, 256, 211, 302, and 296 Re: Relocation of Staff Qualifications From Technical Specifications to the Florida Power and Light and Nextera Energy Quality Assurance Topical Report,” dated June 2, 2025 (ADAMS Accession No. ML25101A190)
- USNRC letter to Dominion Energy, “Issuance of Amendments to Relocate Staff Qualification Requirements,” dated July 11, 2022 (ADAMS Accession No. ML22095A107)

4.3 No Significant Hazards Consideration

NextEra Energy Duane Arnold, LLC (NEDA), pursuant to 50.90, requests an amendment to the Duane Arnold Energy Center (DAEC) Renewed Facility License (RFL) and the Appendix A Technical Specifications (TS). The proposed changes are consistent with resumption of power operation of the reactor and emplacement and retention of fuel into the reactor vessel. The review of the proposed changes is based on the reinstatement of the plant operating licensing basis as it was prior to the 10 CFR 50.82(a)(1) certifications. There are no changes to facility design proposed or required to support this amendment, and no changes proposed to the processes or procedures that were previously used during DAEC power operations. The proposed changes would revise certain requirements contained within the DAEC RFL and TS to reinstate or revise license conditions or specifications that are necessary for power operation. The Table of Contents for the TS are also removed with this amendment. The proposed changes to the DAEC RFL and TS are in accordance with 10 CFR 50.36(c)(1) through 10 CFR 50.36(c)(5).

NEDA has evaluated whether a significant hazards consideration is involved with the proposed amendment(s) 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 changes to the DAEC RFL and TS do not impact the design basis function of plant structures, systems, or components (SSC). The proposed changes do not affect accident initiators or precursors, nor do they alter design assumptions that could increase the probability or consequences of previously evaluated accidents.

   Chapter 15 of the DAEC Updated Final Safety Analysis Report (UFSAR) Revision 25 (ADAMS Accession No. ML19100A042) describes the postulated design basis accidents (DBA) and transient scenarios applicable to DAEC during power operations. The UFSAR will be reinstated to reflect the docketed version that was in effect prior to docketing the 10 CFR 50.82(a) certifications of permanent cessation of power operations and permanent removal of fuel at DAEC. This will include issuance of draft UFSAR Revision 27, which includes previously evaluated accident analyses and safety classification of SSCs to support power operations at DAEC. The proposed changes to the TS revise and/or add license conditions or specifications applicable to the DAEC operating license basis as previously evaluated in UFSAR Revision 25 and reflected in draft UFSAR Revision 27. The proposed changes do not involve physical changes to the facility or in the procedures governing operation of the plant that were in effect prior to 10 CFR 50.82(a)(1) certifications.

   The proposed addition of the TS definitions and rules of usage and application are those applicable to the reinstated DAEC power operations TS and have no impact on plant SSCs or the methods of operation of such SSCs.

   The proposed reinstatement of DAEC safety limits (SLs) and SL violations contain SLs that are necessary to reasonably protect the integrity of certain physical barriers that guard against the uncontrolled release of radioactivity from the reactor core and the Reactor Coolant System pursuant to 10 CFR 50.36(c)(1). Since the proposed SLs are applicable to the power operations at DAEC and provide protection of physical barriers to prevent uncontrolled radioactive release, they would not increase the probability or consequences of previously evaluated DBAs.

   The reinstatement of TS Limiting Conditions for Operation (LCO) and Surveillance Requirements (SR) that are related to the operation of the nuclear reactor or to the prevention, diagnosis, or mitigation of reactor-related transients or accidents do not affect the applicable DBAs previously evaluated in the reinstated UFSAR. The safety functions involving core reactivity control, reactor heat removal, reactor coolant system inventory control, and containment integrity are applicable at DAEC as a power operation plant.

The proposed reinstatement of DAEC design features contain features of the plant such as materials of construction and geometric arrangements, which, if altered or modified, would have a significant effect on safety pursuant to 10 CFR 50.36(c)(4). Since the proposed design features are applicable to power operations at DAEC and provide protection of important design features, they would not increase the probability or consequences of previously evaluated DBAs.

The addition and modification of provisions of the administrative controls of the TS do not affect any accidents applicable during power operation of the plant.

The probability of occurrence of previously evaluated accidents in the UFSAR is not increased since reinstating the previously approved licensing basis, including the RFL and TS, is bounded by the reinstated analyses. Additionally, the proposed changes do not impact the function of plant SSCs.

The removal of the Table of Contents is administrative and affects responsibility for the control of the TOC. Transferring control of TOC changes to the licensee does not affect the operation, physical configuration, or function of plant equipment or systems. It does not impact the initiators or assumptions of analyzed events; nor does it impact the mitigation of accidents or transient events. The change involves no increase in the probability or consequences of an accident.

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 addition of TS that are related only to the operation of the nuclear reactor or only to the prevention, diagnosis, or mitigation of reactor-related transients or accidents, cannot result in different or more adverse failure modes or accidents than previously evaluated because the plant will be operated within the previously approved operating licensing basis.

   The removal of the Table of Contents does not alter the plant configuration, require installation of new equipment, alter assumptions about previously analyzed accidents, or impact the operation or function of plant equipment or systems.

   The proposed changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed), a change in the method of plant operation, or new operator actions. The proposed changes do not introduce failure modes that could result in a new accident, and the changes do not alter assumptions made in the safety analysis. The proposed changes do not

alter or prevent the ability of the operators to perform their intended actions to mitigate the consequences of an accident or even

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

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

Response: No

Margin of safety is associated with confidence in the ability of the fission product barriers (i.e., fuel cladding, reactor coolant system pressure boundary, and containment structure) to limit the level of radiation dose to the public. The proposed amendment would modify the DAEC RFL and TS by adding the portions of the RFL and TS that are credited in the accident analyses for the DBAs in the reinstated UFSAR.

Postulated DBAs involving reactor operation are applicable because the plant will be in a power operation condition. These proposed changes impact operation of the facility and its response to transients or DBAs by reinstating requirements for equipment that is related to the operation of the nuclear reactor or to the prevention, diagnosis, or mitigation of reactor-related transients or accidents. The changes ensure that equipment required to respond to DBAs and transients described in the UFSAR remain capable of performing their safety function. No accident analyses or safety analyses acceptance criteria will be affected by the proposed changes.

The removal of the Table of Contents does not impact any safety assumptions or have the potential to reduce a margin of safety as described in the TS Bases.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, NEDA concludes that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92, and, accordingly, a finding of “no significant hazards consideration” is justified.

4.4 Conclusions

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.

5.0 ENVIRONMENTAL CONSIDERATIONS

In Reference 20 NEDA provided an Environmental Report to the NRC evaluating the potential environmental effects of restart activities, including this proposed license amendment.

6.0 REFERENCES

1. Letter from NextEra Energy Duane Arnold, LLC to USNRC, "Certification of Permanent Removal of Fuel from the Reactor Vessel for Duane Arnold Energy Center," dated October 12, 2020 (ADAMS Accession No. ML20286A317)
2. Letter from NextEra Energy Duane Arnold, LLC to USNRC, "Regulatory Path to Reauthorization of Power Operations," dated January 23, 2025 (ADAMS Accession No. ML25023A265)
3. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “Request for Exemption from Certain Termination of License Requirements of 10 CFR § 50.82,” dated January 23, 2025 (ADAMS Accession No. ML25023A270)
4. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “Transmittal of Revision 25 of the DAEC Updated Final Safety Analysis Report and the Current DAEC Technical Specification Bases,” dated March 21, 2019 (ADAMS Accession No. ML19100A042)
5. USNRC to D. Moul (FPL), “Issuance of Amendment No. 309 to Align Technical Specification Staffing and Administrative requirements,” dated January 2, 2020 (ADAMS Accession No. ML19301C204)
6. USNRC to D. Moul (FPL), “Issuance of Amendment No. 311 re: Permanently Defueled Technical Specifications,” dated July 10, 2020 (ADAMS Accession No. ML20134J104)
7. USNRC to B. Coffey (NextEra Energy, LLC), “Issuance of Amendment No. 315 to Renewed Facility Operating License No. DPR-49 to Revise the Permanently Defueled Technical Specifications to Align to the Requirements for Permanent Removal of Spent Fuel from the Spent Fuel Pool,” January 21, 2022 (ADAMS Accession No. ML21172A217)
8. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “License Amendment Request (TSCR-183): Application to Revise Operating License and Technical Specifications for Permanently Defueled Condition.” dated June 20, 2019 (ADAMS Accession No. ML19176A356)
9. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “Supplement to License Amendment Request (TSCR-183): Application to Revise Technical Specifications for the Permanently Defueled Condition,” dated September 12, 2019 (ADAMS Accession No. ML19261A141)
10. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “License Amendment Request (TSCR-189): Revision to Facility License and Technical Specifications to Reflect Permanent Removal of Spent Fuel from the Spent Fuel Pool,” dated February 19, 2021 (ADAMS Accession No. ML21050A189)

11. USNRC to D. Moul (FPL), “Issuance of Amendment No. 312 re: Removal of License Condition 2.C(3), Fire Protection Program,” dated July 30, 2020 (ADAMS Accession No. ML20184A003)
12. USNRC to D. Moul (FPL), “Issuance of Amendment No. 314 to Renewed Facility Operating License No. DPR-49 to Remove Cyber Security and Security Order License Conditions,” dated May 13, 2021 (ADAMS Accession No. ML21067A642)
13. USNRC to B. Coffey (NextEra Energy, LLC), “Issuance of Amendment No. 316 To Renewed Facility License Operating to Implement the Defueled Physical Security Plan,” dated February 3, 2022 (ADAMS Accession No. ML22028A282)
14. USNRC to B. Coffey (NextEra Energy, LLC), “Issuance of Amendment No. 317 to Renewed Facility License Operating to Implement the Independent Spent Fuel Storage Installation Physical Security Plan,” dated March 10, 2022 (ADAMS Accession No. ML22059A746)
15. USNRC to G. V. Middlesworth (DAEC), “Issuance of Amendment Regarding Extended Power Uprate,” dated November 6, 2001 (ADAMS Accession No. ML013050321)
16. USNRC to M. A. Peifer (DAEC), “Issuance of Amendment Regarding Reactor Building Crane,” dated May 16, 2003 (ADAMS Accession No. ML030990041)
17. Order EA-06-137, “Order Requiring Compliance with Key Radiological Protection Mitigation Strategies,” dated June 20, 2006 (ADAMS Accession No. ML061600023)
18. USNRC to D. Moul (DAEC), “Withdrawal of Interim Compensatory Measure B.1.A in EA-02-026, “Order for Interim Safeguards and Security Compensatory Measures,” and Withdrawal of EA-06-137, “Order Requiring Compliance with Key Radiological Mitigation Strategies,” dated April 20. 2021 (ADAMS Accession No. ML21067A270)
19. USNRC Memo from Ronald R. Bellamy (NRC) to Geoffery E. Grant (NRC), “Response to Technical Assistance Request,” dated August 3, 1998 (ADAMS Accession No. ML20236X389)
20. Letter from NextEra Energy Duane Arnold, LLC to USNRC, “Submittal of Environmental Report in Support of Restart of Duane Arnold Energy Center,” dated November 10, 2025 (ADAMS Accession No. ML25315A003)

LIST OF ATTACHMENTS

Attachment 1 – Proposed Technical Specification Changes (Mark-Up)

Attachment 2 – Revised Technical Specification Pages (Clean, with Proposed Changes)

Attachment 3 – Proposed Technical Specification Bases

ATTACHMENT 1

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

NEXTERA ENERGY DUANE ARNOLD, LLC
CENTRAL IOWA POWER COOPERATIVE
CORN BELT POWER COOPERATIVE
DOCKET 50-331
DUANE ARNOLD ENERGY CENTER
RENEWED FACILITY OPERATING LICENSE

Renewed License No. DPR-49

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

   A. The application for license filed by FPL Energy Duane Arnold, LLC,* Central Iowa Power Cooperative and Corn Belt Power Cooperative (the licensees) complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Deleted;

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

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

   E. NextEra Energy Duane Arnold, LLC is technically qualified and NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative are financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;

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

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

   H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of renewed Facility Operating License No. DPR-49 is in accordance with 10 CFR Part 50, Appendix D, of the Commission’s regulations and all applicable requirements of said Appendix D have been satisfied;

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*On April 16, 2009, the name “FPL Energy Duane Arnold, LLC” was changed to “NextEra Energy Duane Arnold, LLC.”

I. ~~Deleted.~~ The receipt, possession, and use of source, by-product and special nuclear material as authorized by this renewed operating license will be in accordance with the Commission's regulations in 10 CFR Part 30 and 70, including 10 CFR Section 30.33, 70.24 and 70.31.

2. Renewed Facility Operating License No. DPR-49 is hereby issued to NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative (CIPCO) and Corn Belt Power Cooperative (Corn Belt) to read as follows:

A. This renewed operating license applies to the Duane Arnold Energy Center, a ~~permanently defueled~~ boiling water reactor and associated equipment (the facility), owned by NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative and operated by NextEra Energy Duane Arnold, LLC. The facility is located on NextEra Energy Duane Arnold, LLC's, Central Iowa Power Cooperative's and Corn Belt Power Cooperative's site near Palo in Linn County, Iowa. This site consists of approximately 500 acres adjacent to the Cedar River and is described in the "Final Safety Analysis Report" as supplemented and amended (Amendments 1 through 14) and the Environmental Report as supplemented and amended (Supplements 1 through 5).

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

(1) NextEra Energy Duane Arnold, LLC, pursuant to Section104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, ~~and~~ use and operate the facility ~~as required for nuclear fuel storage~~; and CIPCO and Corn Belt to possess the facility at the designated location in Linn County, Iowa, in accordance with the procedures and limitations set forth in this license;

(2) NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material ~~that was used~~ as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Updated Final Safety Analysis Report, as supplemented and amended as of June 1992 and as supplemented by letters dated March 26, 1993, and November 17, 2000.

(3) NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, ~~or~~ sealed sources for reactor instrumentation and radiation monitoring equipment calibration~~,~~ and as fission detectors in amounts as required~~and to possess any byproduct, source and special nuclear material as sealed neutron sources previously used for reactor startup or reactor instrumentation; and fission detectors~~;

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

(5) NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not to separate, such byproduct and special nuclear materials as may be ~~that were~~ produced by the operation of the facility.

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

(1) ~~Deleted~~ Maximum Power Level

NextEra Energy Duane Arnold, LLC is authorized to operate the Duane Arnold Energy Center at steady state reactor core power levels not in excess of 1912 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. ~~317~~XXX, are hereby incorporated in the license. NextEra Energy Duane Arnold, LLC shall operate ~~maintain~~ the facility in accordance with the ~~Permanently Defueled~~ Technical Specifications.

(3) ~~Deleted~~Fire Protection Program

NextEra Energy Duane Arnold, LLC shall implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c), as specified in the licensee amendment request dated August 5, 2011 (and supplements dated October 14, 2011, April 23, 2012, May 23, 2012, July 9, 2012, October 15, 2012, January 11, 2013, February 12, 2013, March 6, 2013, May 1, 2013, May 29, 2013, two supplements dated July 2, 2013, and supplements dated August 5, 2013 and August 28, 2013) and as approved in the safety evaluation report dated September 10, 2013. Except where NRC approval for changes or deviations is required by 10 CFR 50.48(c), and provided no other regulation, technical specification, license condition or requirement would require prior NRC approval, the licensee may make changes to the fire protection program without prior approval of the Commission if those changes satisfy the provisions set forth in 10 CFR 50.48(a) and 10 CFR 50.48(c), the change does not require a change to a technical specification or a license condition, and the criteria listed below are satisfied.

Risk-Informed Changes That May Be Made Without Prior NRC Approval

A risk assessment of the change must demonstrate that the acceptance criteria below are met. The risk assessment approach, methods, and data shall be acceptable to the

NRC and shall be appropriate for the nature and scope of the change being evaluated; be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant. Acceptable methods to assess the risk of the change may include methods that have been used in the peer-reviewed fire PRA model, methods that have been approved by NRC through a plant-specific license amendment or NRC approval of generic methods specifically for use in NFPA 805 risk assessments, or methods that have been demonstrated to bound the risk impact.

(a) Prior NRC review and approval is not required for changes that clearly result in a decrease in risk. The proposed change must also be consistent with the defense-in-depth philosophy and must maintain sufficient safety margins. The change may be implemented following completion of the plant change evaluation.

(b) Prior NRC review and approval is not required for individual changes that result in a risk increase less than $1x10^{-7}$/year (yr) for CDF and less than $1x10^{-8}$/yr for LERF. The proposed change must also be consistent with the defense-in-depth philosophy and must maintain sufficient safety margins. The change may be implemented following completion of the plant change evaluation

Other Changes that May Be Made Without Prior NRC Approval

1. Changes to NFPA 805, Chapter 3, Fundamental Fire Protection Program

   Prior NRC review and approval are not required for changes to the NFPA 805, Chapter 3, fundamental fire protection program elements and design requirements for which an engineering evaluation demonstrates that the alternative to the Chapter 3 element is functionally equivalent or adequate for the hazard. The licensee may use an engineering evaluation to demonstrate that a change to an NFPA 805, Chapter 3, element is functionally equivalent to the corresponding technical requirement. A qualified fire protection engineer shall perform the engineering evaluation and conclude that the change has not affected the functionality of the component, system, procedure, or physical arrangement, using a relevant technical requirement or standard.

   The licensee may use an engineering evaluation to demonstrate that changes to certain NFPA 805, Chapter 3, elements are acceptable because the alternative is "adequate for the hazard." Prior NRC review and approval would not be required for alternatives to four specific sections of NFPA 805, Chapter 3, for which an engineering evaluation demonstrates that the alternative to the Chapter 3 element is adequate for the hazard. A qualified fire protection engineer shall perform the engineering evaluation and conclude that the change has not affected the functionality of the component, system, procedure, or physical arrangement, using a relevant technical requirement or standard. The four specific sections of NFPA 805, Chapter 3, are as follows:

   - "Fire Alarm and Detection Systems" (Section 3.8);
   - "Automatic and Manual Water-Based Fire Suppression Systems" (Section 3.9);
   - "Gaseous Fire Suppression Systems" (Section 3.10); and,
   - "Passive Fire Protection Features" (Section 3.11)

This license condition does not apply to any demonstration of equivalency under Section 1.7 of NFPA 805.

2. Fire Protection Program Changes that Have No More than Minimal Risk Impact

Prior NRC review and approval are not required for changes to the licensee's fire protection program that have been demonstrated to have no more than a minimal risk impact. The licensee may use its screening process as approved in the NRC safety evaluation report dated September 10, 2013, to determine that certain fire protection program changes meet the minimal criterion. The licensee shall ensure that fire protection defense-in-depth and safety margins are maintained when changes are made to the fire protection program.

Transition License Conditions

(1) Before achieving full compliance with 10 CFR 50.48 (c), as specified by (2) and (3) below, risk informed changes to the licensee's fire protection program may not be made without prior NRC review and approval unless the change has been demonstrated to have no more than a minimal risk impact, as described in (2) above.

(2) The licensee shall implement the modifications to its facility, as described in Enclosure 2, Attachment S, Table S-1, "Plant modifications Committed," of DAEC letter NG-13-0287, dated July 2, 2013, to complete the transition to full compliance with 10 CFR 50.48(c) by December 31,2014. The licensee shall maintain appropriate compensatory measures in place until completion of these modifications.

(3) The licensee shall implement the items contained in Enclosure 2, Attachment S, Table S-2, "Implementation Items," of DAEC letter NG-13-0287, dated July 2, 2013 by March 9, 2014.

(4) Deleted

(5) Physical Protection

NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to
10 CFR 72.212(b)(9) and to the authority of 10 CFR 50.90 and
10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Duane Arnold Energy Center Physical Security Plan," submitted by letter dated June 3, 2021, as supplemented.

NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved Duane Arnold Energy Center/NextEra

Energy Duane Arnold, LLC Cyber Security Plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Duane Arnold Energy Center/NextEra Energy Duane Arnold, LLC CSP was approved by License Amendment No. 278, as supplemented by changes approved by license Amendment No. 284 and Amendment 291.

(6) Deleted

(7) Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. ~~315~~XXX, are hereby incorporated into this license. NextEra Energy Duane Arnold, LLC shall operate the facility in accordance with the Additional Conditions.

(8) Deleted

(9) ~~Deleted~~Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(10) ~~Deleted~~The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

(11) ~~Deleted~~The information in the UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be incorporated into the UFSAR no later than the next scheduled update required by 10 CFR 50.71(e) following the issuance of this renewed operating license. Until this update is complete, the licensee may not make changes to the information in the supplement. Following incorporation into the UFSAR, the need for prior Commission approval of any changes will be governed by 10 CFR 50.59.

(12) ~~Deleted~~The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), and as supplemented by Appendix A of NUREG-1955, "Safety Evaluation Report Related to the License Renewal of Duane Arnold Energy Center," dated November 2010, as supplemented by letter from the licensee to the NRC dated November 23, 2010, describes certain programs to be implemented and activities to be completed before the period of extended operation.

a. NextEra Energy Duane Arnold, LLC shall implement those new programs and enhancements to existing programs no later than February 21, 2014.

b. NextEra Energy Duane Arnold, LLC shall complete those activities no later than February 21, 2014.

The licensee shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

(13) ~~Deleted~~The licensee shall implement the most recent staff-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as the method to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix H. Any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule which affects the time of withdrawal of any surveillance capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in a manner which maintains them in a condition which would support re-insertion into the reactor pressure vessel if necessary.

D. This license is effective as of the date of issuance and shall expire at midnight February 21, 2034. ~~is effective until the Commission notifies the licensee in writing that the license is terminated~~

FOR THE NUCLEAR REGULATORY COMMISSION

Original signed by Eric J. Leeds

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Appendix A Technical Specifications
2. Appendix B Additional Conditions

Date of Issuance: December 16, 2010

APPENDIX B

ADDITIONAL CONDITIONS

LICENSE NO. DPR-49

NextEra Energy Duane Arnold, LLC (the term licensee in Appendix B refers to NextEra Energy Duane Arnold, LLC or prior license holders) shall comply with the following conditions on the schedule noted below:

Amendment Number	Additional Conditions	Implementation Date
223 275	DELETED	
260 (1) 275	NextEra Energy Duane Arnold shall take all necessary steps to ensure that the external trust fund is established at the time of the closing of the transfer of the license from Interstate Power (IPL) to FPLE Duane Arnold is maintained in accordance with the requirements of the December 23, 2005 order approving the license transfer, NRC regulations, and consistent with the safety evaluation supporting the order. The trust agreement shall be in a form acceptable to the NRC.	This amendment is effective immediately and shall be implemented within 30 days of the date of this amendment.
260 (2) 279	DELETED	
260 (3)	DELETED	
XXX	The licensee is authorized to load fuel and perform low power testing, but may not exceed 5 percent of rated thermal power until, following the conduct of the exercise required by paragraph IV.F.2 of Appendix E to 10 CFR Part 50, the NRC notifies the licensee that the Federal Emergency Management Agency (FEMA): (1) has not identified any deficiencies in the state of offsite emergency preparedness; or (2) has informed the NRC that any offsite deficiencies have been corrected.	With implementation of this amendment.

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Insert the following TS as shown in Attachment 2.

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4.0 DESIGN FEATURES

4.1 Site Location

The plant site, which consists of approximately 500 acres, is adjacent to the Cedar River approximately 2.5 miles northeast of the Village of Palo, Iowa. Distance from the reactor centerline to the nearest site boundary is approximately 2000 ft. The boundary of the exclusion area defined in 10 CFR 100 is delineated by the property lines. The distance to the outer boundary of the low population zone is 6 miles. The plan of the site is shown on UFSAR Figures 1.2-1 and 1.2-2.

4.2 ~~Deleted~~Reactor Core

4.2.1 Fuel Assemblies

The reactor shall consist of not more than 368 fuel assemblies. Each assembly shall consist of a matrix of Zircalloy or ZIRLO fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material, and water rods. Limited substitution of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with NRC staff approved codes and methods and have been shown by tests or analyses to comply with all safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 89 cruciform shaped control rod assemblies. The control materials shall be boron carbide and hafnium metal, as approved by the NRC.

4.0 DESIGN FEATURES

4.3 Fuel Storage

~~Spent fuel shall not be stored in the spent fuel pool.~~4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having the following limits for maximum k-infinity in the normal reactor core configuration at cold conditions and maximum lattice-average U-235 enrichment weight percent:

		k-∞	wt %
i)	7x7 and 8x8 pin arrays (Legacy Fuel Assemblies only; Holtec and PaR racks)	≤ 1.29	≤ 4.6
ii)	10x10 pin arrays (Holtec and PaR racks)	≤ 1.29	≤ 4.95

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in 9.1 of the UFSAR; and

c. A nominal 6.060 inches for HOLTEC designed and 6.625 inches for PaR designed center to center distance between fuel assemblies placed in the storage racks.

d. The Boral neutron absorber shall have a ^{10}B areal density greater than or equal to 0.0162 grams $^{10}B/cm^2$ with an uncertainty of 0.0012 grams $^{10}B/cm^2$.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.31 in the normal reactor core configuration at cold conditions;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. $k_{eff} \leq 0.90$ if dry, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR; and

d. A nominal 6.625 inch center to center distance between fuel assemblies placed in storage racks.

4.0 DESIGN FEATURES

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 831 ft. – 2 3/4 in.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 2563 fuel assemblies in a vertical orientation, including no more than 152 fuel assemblies stored in the cask pit in accordance with UFSAR Section 9.1.

The new fuel storage vault is equipped with racks for storage of up to 110 fuel assemblies in a vertical orientation.

Insert the following TS as shown in Attachment 2.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibilities
5.2 Organization
5.3 Unit Staff Qualifications
5.4 Procedures
5.5 Programs and Manuals

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 DELETED

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Assessment Manual (ODAM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODAM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in Regulatory Guide 4.8. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Material Release Report

The Radioactive Material Release Report covering the operation of the ~~facility~~unit during the previous calendar year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the ~~facility~~unit. The material provided shall be consistent with the objectives outlined in the ODAM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.4 DELETED

5.6 Reporting Requirements (continued)

5.6.5 ~~Deleted~~CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. The Average Planar Linear Heat Generation Rate (APLHGR) for Specification 3.2.1;

2. The Minimum Critical Power Ratio (MCPR) for Specification 3.2.2;

3. Exclusion Region in the Power/Flow Map for Specification 3.4.1; and

4. The Minimum Critical Power Ratios (MCPR) in Table 3.3.2.1-1 for Specification 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC in General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A, (GESTAR II). The revision number is the one approved at the time the reload fuel analyses are performed.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 ~~Deleted~~PAM Report

When a report is required by Condition B or F of LCO 3.3.3.1, “Post Accident Monitoring (PAM) Instrumentation,” a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method(s) of monitoring, describe the degree to which the alternate method(s) are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6 Reporting Requirements (continued)

5.6.7 ~~Deleted~~Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

i) Limiting Conditions for Operation Section 3.4.9, "RCS Pressure and Temperature (P/T) Limits"

ii) Surveillance Requirements Section 3.4.9, "RCS Pressure and Temperature (P/T) Limits"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

i) SIR-05-044-A, "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," Revision 1, dated June 2013.

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously transmits dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(continued)

5.7 High Radiation Area (continued)

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

(continued)

5.7 High Radiation Area (continued)

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, or personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

(continued)

5.7 High Radiation Area (continued)

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible light shall be activated at the area as a warning device.

ATTACHMENT 2

REVISED TECHNICAL SPECIFICATION PAGES
(CLEAN, WITH PROPOSED CHANGES)

NEXTERA ENERGY DUANE ARNOLD, LLC
CENTRAL IOWA POWER COOPERATIVE
CORN BELT POWER COOPERATIVE
DOCKET 50-331
DUANE ARNOLD ENERGY CENTER
RENEWED FACILITY OPERATING LICENSE

Renewed License No. DPR-49

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

   A. The application for license filed by FPL Energy Duane Arnold, LLC,* Central Iowa Power Cooperative and Corn Belt Power Cooperative (the licensees) complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Deleted;

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

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

   E. NextEra Energy Duane Arnold, LLC is technically qualified and NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative are financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;

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

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

   H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of renewed Facility Operating License No. DPR-49 is in accordance with 10 CFR Part 50, Appendix D, of the Commission’s regulations and all applicable requirements of said Appendix D have been satisfied;

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*On April 16, 2009, the name “FPL Energy Duane Arnold, LLC” was changed to “NextEra Energy Duane Arnold, LLC.”

I. The receipt, possession, and use of source, by-product and special nuclear material as authorized by this renewed operating license will be in accordance with the Commission's regulations in 10 CFR Part 30 and 70, including 10 CFR Section 30.33, 70.24 and 70.31.

2. Renewed Facility Operating License No. DPR-49 is hereby issued to NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative (CIPCO) and Corn Belt Power Cooperative (Corn Belt) to read as follows:

A. This renewed operating license applies to the Duane Arnold Energy Center, a boiling water reactor and associated equipment (the facility), owned by NextEra Energy Duane Arnold, LLC, Central Iowa Power Cooperative and Corn Belt Power Cooperative and operated by NextEra Energy Duane Arnold, LLC. The facility is located on NextEra Energy Duane Arnold, LLC's, Central Iowa Power Cooperative's and Corn Belt Power Cooperative's site near Palo in Linn County, Iowa. This site consists of approximately 500 acres adjacent to the Cedar River and is described in the "Final Safety Analysis Report" as supplemented and amended (Amendments 1 through 14) and the Environmental Report as supplemented and amended (Supplements 1 through 5).

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

(1) NextEra Energy Duane Arnold, LLC, pursuant to Section104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use and operate the facility; and CIPCO and Corn Belt to possess the facility at the designated location in Linn County, Iowa, in accordance with the procedures and limitations set forth in this license;

(2) NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Updated Final Safety Analysis Report, as supplemented and amended as of June 1992 and as supplemented by letters dated March 26, 1993, and November 17, 2000.

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

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

(5) NextEra Energy Duane Arnold, LLC, pursuant to the Act and 10 CFR Parts 30 and

70, to possess, but not to separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

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

(1) Maximum Power Level

NextEra Energy Duane Arnold, LLC is authorized to operate the Duane Arnold Energy Center at steady state reactor core power levels not in excess of 1912 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. XXX, are hereby incorporated in the license. NextEra Energy Duane Arnold, LLC shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection Program

NextEra Energy Duane Arnold, LLC shall implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c), as specified in the licensee amendment request dated August 5, 2011 (and supplements dated October 14, 2011, April 23, 2012, May 23, 2012, July 9, 2012, October 15, 2012, January 11, 2013, February 12, 2013, March 6, 2013, May 1, 2013, May 29, 2013, two supplements dated July 2, 2013, and supplements dated August 5, 2013 and August 28, 2013) and as approved in the safety evaluation report dated September 10, 2013. Except where NRC approval for changes or deviations is required by 10 CFR 50.48(c), and provided no other regulation, technical specification, license condition or requirement would require prior NRC approval, the licensee may make changes to the fire protection program without prior approval of the Commission if those changes satisfy the provisions set forth in 10 CFR 50.48(a) and 10 CFR 50.48(c), the change does not require a change to a technical specification or a license condition, and the criteria listed below are satisfied.

Risk-Informed Changes That May Be Made Without Prior NRC Approval

A risk assessment of the change must demonstrate that the acceptance criteria below are met. The risk assessment approach, methods, and data shall be acceptable to the NRC and shall be appropriate for the nature and scope of the change being evaluated; be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant. Acceptable methods to assess the risk of the change may include methods that have been used in the peer-reviewed fire PRA model, methods that have been approved by NRC through a plant-specific license amendment or NRC approval of generic methods specifically for use in NFPA 805 risk assessments, or methods that have been demonstrated to bound the risk impact.

(a) Prior NRC review and approval is not required for changes that clearly result in a decrease in risk. The proposed change must also be consistent with the defense-in-depth philosophy and must maintain sufficient safety margins. The change may be implemented following completion of the plant change evaluation.

(b) Prior NRC review and approval is not required for individual changes that result in a risk increase less than $1x10^{-7}$/year (yr) for CDF and less than $1x10^{-8}$/yr for LERF. The proposed change must also be consistent with the defense-in-depth philosophy and must maintain sufficient safety margins. The change may be implemented following completion of the plant change evaluation

Other Changes that May Be Made Without Prior NRC Approval

1. Changes to NFPA 805, Chapter 3, Fundamental Fire Protection Program

   Prior NRC review and approval are not required for changes to the NFPA 805, Chapter 3, fundamental fire protection program elements and design requirements for which an engineering evaluation demonstrates that the alternative to the Chapter 3 element is functionally equivalent or adequate for the hazard. The licensee may use an engineering evaluation to demonstrate that a change to an NFPA 805, Chapter 3, element is functionally equivalent to the corresponding technical requirement. A qualified fire protection engineer shall perform the engineering evaluation and conclude that the change has not affected the functionality of the component, system, procedure, or physical arrangement, using a relevant technical requirement or standard.

   The licensee may use an engineering evaluation to demonstrate that changes to certain NFPA 805, Chapter 3, elements are acceptable because the alternative is "adequate for the hazard." Prior NRC review and approval would not be required for alternatives to four specific sections of NFPA 805, Chapter 3, for which an engineering evaluation demonstrates that the alternative to the Chapter 3 element is adequate for the hazard. A qualified fire protection engineer shall perform the engineering evaluation and conclude that the change has not affected the functionality of the component, system, procedure, or physical arrangement, using a relevant technical requirement or standard. The four specific sections of NFPA 805, Chapter 3, are as follows:

   - "Fire Alarm and Detection Systems" (Section 3.8);
   - "Automatic and Manual Water-Based Fire Suppression Systems" (Section 3.9);
   - "Gaseous Fire Suppression Systems" (Section 3.10); and,
   - "Passive Fire Protection Features" (Section 3.11)

   This license condition does not apply to any demonstration of equivalency under Section 1.7 of NFPA 805.

2. Fire Protection Program Changes that Have No More than Minimal Risk Impact

   Prior NRC review and approval are not required for changes to the licensee's fire protection program that have been demonstrated to have no more than a minimal

risk impact. The licensee may use its screening process as approved in the NRC safety evaluation report dated September 10, 2013, to determine that certain fire protection program changes meet the minimal criterion. The licensee shall ensure that fire protection defense-in-depth and safety margins are maintained when changes are made to the fire protection program.

Transition License Conditions

(1) Before achieving full compliance with 10 CFR 50.48 (c), as specified by (2) and (3) below, risk informed changes to the licensee's fire protection program may not be made without prior NRC review and approval unless the change has been demonstrated to have no more than a minimal risk impact, as described in (2) above.

(2) The licensee shall implement the modifications to its facility, as described in Enclosure 2, Attachment S, Table S-1, "Plant modifications Committed," of DAEC letter NG-13-0287, dated July 2, 2013, to complete the transition to full compliance with 10 CFR 50.48(c) by December 31,2014. The licensee shall maintain appropriate compensatory measures in place until completion of these modifications.

(3) The licensee shall implement the items contained in Enclosure 2, Attachment S, Table S-2, "Implementation Items," of DAEC letter NG-13-0287, dated July 2, 2013 by March 9, 2014.

(4) Deleted

(5) Physical Protection

NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to
10 CFR 72.212(b)(9) and to the authority of 10 CFR 50.90 and
10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Duane Arnold Energy Center Physical Security Plan," submitted by letter dated June 3, 2021, as supplemented.

NextEra Energy Duane Arnold, LLC shall fully implement and maintain in effect all provisions of the Commission-approved Duane Arnold Energy Center/NextEra Energy Duane Arnold, LLC Cyber Security Plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Duane Arnold Energy Center/NextEra Energy Duane Arnold, LLC CSP was approved by License Amendment No. 278, as supplemented by changes approved by license Amendment No. 284 and Amendment 291.

(6) Deleted

(7) Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. XXX, are hereby incorporated into this license. NextEra Energy Duane Arnold, LLC shall operate the facility in accordance with the Additional Conditions.

(8) Deleted

(9) Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(10) The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

(11) The information in the UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be incorporated into the UFSAR no later than the next scheduled update required by 10 CFR 50.71(e) following the issuance of this renewed operating license. Until this update is complete, the licensee may not make changes to the information in the supplement. Following incorporation into the UFSAR, the need for prior Commission approval of any changes will be governed by 10 CFR 50.59.

(12) The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), and

as supplemented by Appendix A of NUREG-1955, “Safety Evaluation Report Related to the License Renewal of Duane Arnold Energy Center,” dated November 2010, as supplemented by letter from the licensee to the NRC dated November 23, 2010, describes certain programs to be implemented and activities to be completed before the period of extended operation.

a. NextEra Energy Duane Arnold, LLC shall implement those new programs and enhancements to existing programs no later than February 21, 2014.

b. NextEra Energy Duane Arnold, LLC shall complete those activities no later than February 21, 2014.

The licensee shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

(13) The licensee shall implement the most recent staff-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as the method to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix H. Any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule which affects the time of withdrawal of any surveillance capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in a manner which maintains them in a condition which would support re-insertion into the reactor pressure vessel if necessary.

D. This license is effective as of the date of issuance and shall expire at midnight February 21, 2034.

FOR THE NUCLEAR REGULATORY COMMISSION

Original signed by Eric J. Leeds

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Appendix A Technical Specifications
2. Appendix B Additional Conditions

Date of Issuance: December 16, 2010

APPENDIX B

ADDITIONAL CONDITIONS

LICENSE NO. DPR-49

NextEra Energy Duane Arnold, LLC (the term licensee in Appendix B refers to NextEra Energy Duane Arnold, LLC or prior license holders) shall comply with the following conditions on the schedule noted below:

Amendment Number	Additional Conditions	Implementation Date
223 275	DELETED	
260 (1) 275	NextEra Energy Duane Arnold shall take all necessary steps to ensure that the external trust fund is established at the time of the closing of the transfer of the license from Interstate Power (IPL) to FPLE Duane Arnold is maintained in accordance with the requirements of the December 23, 2005 order approving the license transfer, NRC regulations, and consistent with the safety evaluation supporting the order. The trust agreement shall be in a form acceptable to the NRC.	This amendment is effective immediately and shall be implemented within 30 days of the date of this amendment.
260 (2) 279	DELETED	
260 (3)	DELETED	
XXX	The licensee is authorized to load fuel and perform low power testing, but may not exceed 5 percent of rated thermal power until, following the conduct of the exercise required by paragraph IV.F.2 of Appendix E to 10 CFR Part 50, the NRC notifies the licensee that the Federal Emergency Management Agency (FEMA): (1) has not identified any deficiencies in the state of offsite emergency preparedness; or (2) has informed the NRC that any offsite deficiencies have been corrected.	With implementation of this amendment.

1.0 USE AND APPLICATION

1.1 Definitions

----------NOTE----------
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)	The APLHGR shall be applicable to a specific planar height and is equal to the sum of the heat generation rate per unit length of fuel rod for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle at the height.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with Resistance Temperature Detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions

CHANNEL FUNCTIONAL TEST	A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. The following exceptions are not considered to be CORE ALTERATIONS: a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); and b. Control rod movement, provided there are no fuel assemblies in the associated core cell. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/ml), that alone would produce the same dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The dose conversion factors used for this calculation shall be those listed in Federal Guidance Report (FGR) 11, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion,” 1989 and FGR 12, “External Exposure to Radionuclides in Air, Water, and Soil,” 1993.

1.1 Definitions

DRAIN TIME	The DRAIN TIME is the time it would take for the water inventory in and above the Reactor Pressure Vessel (RPV) to drain to the Reactor Vessel Water Level Safety Limit of T.S. 2.1.1.3 assuming: a) The water inventory above the T.S. 2.1.1.3 Safety Limit is divided by the limiting drain rate; b) The limiting drain rate is the larger of the drain rate through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error), for all penetration flow paths below the T.S. 2.1.1.3 Safety Limit except: 1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are locked, sealed, or otherwise secured in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths; 2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the T.S. 2.1.1.3 Safety Limit when actuated by RPV water level isolation instrumentation; or 3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the T.S. 2.1.1.3 Safety Limit by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power. c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory; d) No additional draining events occur; and e) Realistic cross-sectional areas and drain rates are used. A bounding DRAIN TIME may be used in lieu of a calculated value.

1.1 Definitions

END OF CYCLE RECIRCULATION PUMP TRIP (EOC RPT) SYSTEM RESPONSE TIME	The EOC RPT SYSTEM RESPONSE TIME shall be that time interval from initial signal generation by the associated turbine stop valve limit switch or from when the turbine control valve hydraulic oil control oil pressure drops below the pressure switch setpoint to actuation of the breaker secondary (auxiliary) contact. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
INSERVICE TESTING	The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).
LEAKAGE	LEAKAGE shall be: a. <u>Identified LEAKAGE</u> 1. LEAKAGE into the drywell, such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or 2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known not to interfere with the operation of leakage detection systems; b. <u>Unidentified LEAKAGE</u> All LEAKAGE into the drywell that is not identified LEAKAGE; c. <u>Total LEAKAGE</u> Sum of the identified and unidentified LEAKAGE.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components required for OPERABILITY of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.

1.1 Definitions

MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience transition boiling, divided by the actual assembly operating power. Transition boiling means the boiling regime between nucleate and film boiling. Transition boiling is the regime in which both nucleate and film boiling occur intermittently with neither type being completely stable.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE — OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.7.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1912 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

1.1 Definitions

SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that: a. The reactor is xenon free; b. The moderator temperature is ≥ 68°F (20°C), corresponding to the most reactive state; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn with the core in its most reactive state during the operating cycle. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTOR MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	Run	NA
2	Startup	Refuel[(a)] or Startup/Hot Standby	NA
3	Hot Shutdown[(a)]	Shutdown	$>$ 212
4	Cold Shutdown[(a)]	Shutdown	$\leq$ 212
5	Refueling[(b)]	Shutdown or Refuel	NA

(a) All reactor vessel head closure bolts fully tensioned.

(b) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentions of the logical connectors.

When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLES (continued)

Example 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

Example 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Times(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

1.3 Completion Times

DESCRIPTION (continued)

However, when a subsequent division, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified “time zero.” This modified “time zero” may be expressed as a repetitive time (i.e., “once per 8 hours,” where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase “from discovery . . .” Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Condition A and B in Example 1.3-3 may not be extended.

1.3 Completion Times

EXAMPLES The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to be in MODE 3 within 12 hours AND in MODE 4 within 36 hours. A total of 12 hours is allowed for reaching MODE 3 and a total of 36 hours (not 48 hours) is allowed for reaching MODE 4 from the time that Condition B was entered. If MODE 3 is reached within 6 hours, the time allowed for reaching MODE 4 is the next 30 hours because the total time allowed for reaching MODE 4 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 4 is the next 36 hours.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Conditions A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable pump. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

EXAMPLES (continued)

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

On restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for $>$ 7 days.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

EXAMPLES (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

The Completion Times of Conditions A and B are modified by a logical connector, with a separate 10 day Completion Time measured from the time it was discovered the LCO was not met. In this example, without the separate Completion Time, it would be possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. The separate Completion Time modified by the phrase “from discovery of failure to meet the LCO” is designed to prevent indefinite continued operation while not meeting the LCO. This Completion Time allows for an exception to the normal “time zero” for beginning the Completion Time “clock”. In this instance, the Completion Time “time zero” is specified as commencing at the time the LCO was initially not met, instead of at the time the associated Condition was entered.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for $>$ 4 hours.

If the Completion Time of 4 hours (plus the extension) expires while one or more valves are still inoperable, Condition B is entered.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

1.3 Completion Times

EXAMPLES (continued)

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

1.3 Completion Times

EXAMPLES (continued)

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a “once per” Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated. AND A.2 Restore subsystem to OPERABLE status.	1 hour AND Once per 8 hours thereafter 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each “Once per 8 hours thereafter” interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for

1.3 Completion Times

EXAMPLES (continued)

Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME	When “Immediately” is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The “specified Frequency” is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The “specified Frequency” consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are “otherwise stated” conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only “required” when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of “met” or “performed” in these instances conveys specific meanings. A Surveillance is “met” only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being “performed,” constitutes a Surveillance not “met.” “Performance” refers only to the requirement to specifically determine the ability to meet the acceptance criteria. Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

1.4 Frequency

DESCRIPTION (continued)

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discusses these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO).

1.4 Frequency

EXAMPLES (continued)

If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The Surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the MODE or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after $\geq$ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level $<$ 25% RTP to $\geq$ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by SR 3.0.2.

1.4 Frequency

EXAMPLES (continued)

"Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be performed until 12 hours after ≥ 25% RTP. ----------	
Perform channel adjustment.	7 days

The interval continues whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day interval (plus the extension allowed by SR 3.0.2), but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours (plus the extension allowed by SR 3.0.2) with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval (plus the extension allowed by SR 3.0.2) there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be met in MODE 1. ----------	
Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

EXAMPLES (continued)

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be performed in MODE 1. ----------	
Perform complete cycle of the valve	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2 or 3 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be met in MODE 3. ----------	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an “otherwise stated” exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 Fuel Cladding Integrity – With the reactor steam dome pressure < 686 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 21.7% RTP.

2.1.1.2 MCPR – With the reactor steam dome pressure ≥ 686 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.08 for two recirculation loop operation or ≥ 1.11 for single recirculation loop operation.

2.1.1.3 Reactor Vessel Water Level – Reactor vessel water level shall be greater than 15 inches above the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1335 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Fully insert all insertable rods.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1

LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2, LCO 3.0.7, LCO 3.0.8, and LCO 3.0.9.

LCO 3.0.2

Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3

When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 2 within 9 hours;

b. MODE 3 within 13 hours; and

c. MODE 4 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, and 3.

LCO 3.0.4

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

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

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

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

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

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

LCO 3.0.5

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

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.11, “Safety Function Determination Program (SFDP).” If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system’s Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

LCO 3.0.7

Special Operations LCOs in Section 3.10 allow specified Technical Specifications (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Special Operations LCOs is optional. When a Special Operations LCO is desired to be met but is not met, the ACTIONS of the Special Operations LCO shall be met. When a Special Operations LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with the other applicable Specifications.

3.0 LCO APPLICABILITY

LCO 3.0.8

When one or more required snubbers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if risk is assessed and managed, and:

a. the snubbers not able to perform their associated support function(s) are associated with only one train or subsystem of multiple train or subsystem supported system or are associated with a single train or subsystem supported system and are able to perform their associated support function within 72 hours; or

b. the snubbers not able to perform their associated support function (s) are associated with more than one train or subsystem of a multiple train or subsystem supported system and are able to perform their associated support function within 12 hours.

At the end of the specified period the required snubbers must be able to perform their associated support function(s), or the affected supported system LCO(s) shall be declared not met.

LCO 3.0.9

When one or more required barriers are unable to perform their related support function(s), any supported system LCO(s) are not required to be declared not met solely for this reason for up to 30 days provided that at least one train or subsystem of the supported system is OPERABLE and supported by barriers capable of providing their related support function(s), and risk is assessed and managed. This specification may be concurrently applied to more than one train or subsystem of a multiple train or subsystem supported system provided at least one train or subsystem of the supported system is OPERABLE and the barriers supporting each of these trains or subsystems provide their related support function(s) for different categories of initiating events.

For the purposes of this specification, the High Pressure Coolant Injection system, the Reactor Core Isolation Cooling system, and the Automatic Depressurization System are considered independent subsystems of a single system.

If the required OPERABLE train or subsystem becomes inoperable while this specification is in use, it must be restored to OPERABLE status within 24 hours or the provisions of this specification cannot be applied to the trains or subsystems supported by the barriers that cannot perform their related support function(s).

At the end of the specified period, the required barriers must be able to perform their related support function(s) or the supported system LCO (s) shall be declared not met.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as “once,” the above interval extension does not apply.

If a Completion Time requires periodic performance on a “once per . . .” basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

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

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

3.0 SR APPLICABILITY

SR 3.0.4

Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency, except as provided by SR 3.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be:

a. $\geq$ 0.38% Δk/k, with the highest worth control rod analytically determined; or

b. $\geq$ 0.28% Δk/k, with the highest worth control rod determined by test.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limits in MODE 1 or 2.	A.1 Restore SDM to within limits.	6 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	12 hours
C. SDM not within limits in MODE 3.	C.1 Initiate action to fully insert all insertable control rods.	Immediately
D. SDM not within limits in MODE 4.	D.1 Initiate action to fully insert all insertable control rods. AND	Immediately (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.2 Initiate action to restore secondary containment to OPERABLE status. AND D.3 Initiate action to restore one Standby Gas Treatment (SBGT) subsystem to OPERABLE status. AND D.4 Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	1 hour 1 hour 1 hour
E. SDM not within limits in MODE 5.	E.1 Suspend CORE ALTERATIONS except for control rod insertion and fuel assembly removal. AND E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. AND	Immediately Immediately (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.3 Initiate action to restore secondary containment to OPERABLE status. AND	1 hour
	E.4 Initiate action to restore one SBGT subsystem to OPERABLE status. AND	1 hour
	E.5 Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM is: a. $\geq$ 0.38% $\Delta k/k$ with the highest worth control rod analytically determined; or b. $\geq$ 0.28% $\Delta k/k$ with the highest worth control rod determined by test.	Prior to each in vessel fuel movement during fuel loading sequence AND Once within 4 hours after criticality following fuel movement within the reactor pressure vessel or control rod replacement

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Reactivity Anomalies

LCO 3.1.2 The reactivity difference between the monitored core k_{eff} and the predicted core k_{eff} shall be within $\pm$ 1% $\Delta k/k$.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Core reactivity difference not within limit.	A.1 Restore core reactivity difference to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.2.1 Verify core reactivity difference between the monitored core k_{eff} and the predicted core k_{eff} is within $\pm$ 1% $\Delta k/k$.	Once within 24 hours after reaching equilibrium conditions following startup after fuel movement within the reactor pressure vessel or control rod replacement AND 1000 MWD/T thereafter during operations in MODE 1

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Control Rod OPERABILITY

LCO 3.1.3 Each control rod shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each control rod.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One withdrawn control rod stuck.	----------NOTE---------- Rod Worth Minimizer (RWM) may be bypassed as allowed by LCO 3.3.2.1, “Control Rod Block Instrumentation,” if required, to allow continued operation. --- A.1 Verify stuck control rod separation criteria are met. AND A.2 Disarm the associated Control Rod Drive (CRD). AND	Immediately 2 hours (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Perform SR 3.1.3.2 for each withdrawn OPERABLE control rod. AND	24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the Low Power Setpoint (LPSP) of the RWM.
	A.4 Perform SR 3.1.1.1	72 hours
B. Two or more withdrawn control rods stuck.	B.1 Be in MODE 3.	12 hours
C. One or more control rods inoperable for reasons other than Condition A or B.	C.1 ----------NOTE---------- RWM may be bypassed as allowed by LCO 3.3.2.1, if required, to allow insertion of inoperable control rod and continued operation. ---------- Fully insert inoperable control rod. AND	 3 hours
	C.2 Disarm the associated CRD.	4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. ----------NOTE---------- Not applicable when THERMAL POWER > 10% RTP. ---------- Two or more inoperable control rods not in compliance with Banked Position Withdrawal Sequence (BPWS) and not separated by two or more OPERABLE control rods.	D.1 Restore compliance with BPWS. OR D.2 Restore control rod to OPERABLE status.	4 hours 4 hours
E. Required Action and associated Completion Time of Condition A, C, or D, not met. OR Nine or more control rods inoperable.	E.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Determine the position of each control rod.	In accordance with the Surveillance Frequency Control Program
SR 3.1.3.2	----------NOTE---------- Not required to be performed until 31 days after the control rod is withdrawn and THERMAL POWER is greater than 20% RTP. ---------- Insert each withdrawn control rod at least one notch.	In accordance with the Surveillance Frequency Control Program
SR 3.1.3.3	Verify each control rod scram time from fully withdrawn to notch position 04 is ≤ 7 seconds.	In accordance with SR 3.1.4.1 and SR 3.1.4.2
SR 3.1.3.4	Verify each withdrawn control rod does not go to the withdrawn overtravel position.	Each time the contr rod is withdrawn to "full out" position AND Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect coupling

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Control Rod Scram Times

LCO 3.1.4

a. No more than 6 OPERABLE control rods shall be "slow," in accordance with Table 3.1.4-1; and

b. No more than 2 OPERABLE control rods that are "slow" shall occupy adjacent locations.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
During single control rod scram time Surveillances, the Control Rod Drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	Prior to exceeding 40% RTP after each refueling AND Prior to exceeding 40% RTP after each reactor shutdown ≥ 120 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	Prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time AND Prior to exceeding 40% RTP after fuel movement within the reactor pressure vessel

Table 3.1.4-1 (page 1 of 1)
Control Rod Scram Times

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

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

2. Enter applicable Conditions and Required Actions of LCO 3.1.3, “Control Rod OPERABILITY,” for control rods with scram times > 7 seconds to notch position 04. These control rods are inoperable, in accordance with SR 3.1.3.3, and are not considered “slow.”

NOTCH POSITION	SCRAM TIMES[(a)] (seconds) when REACTOR STEAM DOME PRESSURE ≥ 800 psig
46	0.44
38	0.93
26	1.83
06	3.35

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Control Rod Scram Accumulators

LCO 3.1.5 Each control rod scram accumulator shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each control rod scram accumulator.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One control rod scram accumulator inoperable with reactor steam dome pressure $\geq$ 900 psig.	A.1 ----------NOTE---------- Only applicable if the associated control rod scram time was within the limits of Table 3.1.4-1 during the last scram time Surveillance. ---------- Declare the associated control rod scram time "slow."	8 hours
	OR	
	A.2 Declare the associated control rod inoperable.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two or more control rod scram accumulators inoperable with reactor steam dome pressure $\geq$ 900 psig.	B.1 Restore charging water header pressure to $\geq$ 940 psig.	1 hour from discovery of condition B concurrent with charging water header pressure $<$ 940 psig
	AND	
	B.2.1 ----------NOTE---------- Only applicable if the associated control rod scram time was within the limits of Table 3.1.4-1 during the last scram time Surveillance. ---------- Declare the associated control rod scram time "slow."	1 hour
	OR	
	B.2.2 Declare the associated control rod inoperable.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig.	C.1 Verify all control rods associated with inoperable accumulators are fully inserted. AND C.2 Declare the associated control rod inoperable.	Immediately upon discovery of charging water header pressure < 940 psig 1 hour
D. Required Action and associated Completion Time of Required Action B.1 or C.1 not met.	D.1 ----------NOTE---------- Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. ---------- Place the reactor mode switch in the Shutdown position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each control rod scram accumulator pressure is ≥ 940 psig.	In accordance with the Surveillance Frequency Control Program

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Rod Pattern Control

LCO 3.1.6 OPERABLE control rods shall comply with the requirements of the Banked Position Withdrawal Sequence (BPWS).

APPLICABILITY: MODES 1 and 2 with THERMAL POWER ≤ 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more OPERABLE control rods not in compliance with BPWS.	A.1 ----------NOTE---------- Rod Worth Minimizer (RWM) may be bypassed as allowed by LCO 3.3.2.1, “Control Rod Block Instrumentation.” ---------- Move associated control rod(s) to correct position.	8 hours
	OR	
	A.2 Declare associated control rod(s) inoperable.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Nine or more OPERABLE control rods not in compliance with BPWS.	B.1 ----------NOTE---------- Rod Worth Minimizer (RWM) may be bypassed as allowed by LCO 3.3.2.1. ---------- Suspend withdrawal of control rods.	Immediately
	AND	
	B.2 Place the reactor mode switch in the Shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify all OPERABLE control rods comply with BPWS.	In accordance with the Surveillance Frequency Control Program

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SLC subsystem inoperable.	A.1 Restore SLC subsystem to OPERABLE status.	7 days
B. Two SLC subsystems inoperable.	B.1 Restore one SLC subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.3	Verify temperature of pump suction piping is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.4	Verify continuity of explosive charge.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.5	Verify the concentration of boron in solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after water or boron is added to solution AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.6	Verify each pump develops a flow rate ≥ 26.2 gpm at a discharge pressure ≥ 1150 psig.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.1.7.7	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.8	Verify all heat traced piping between storage tank and pump suction is unblocked.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

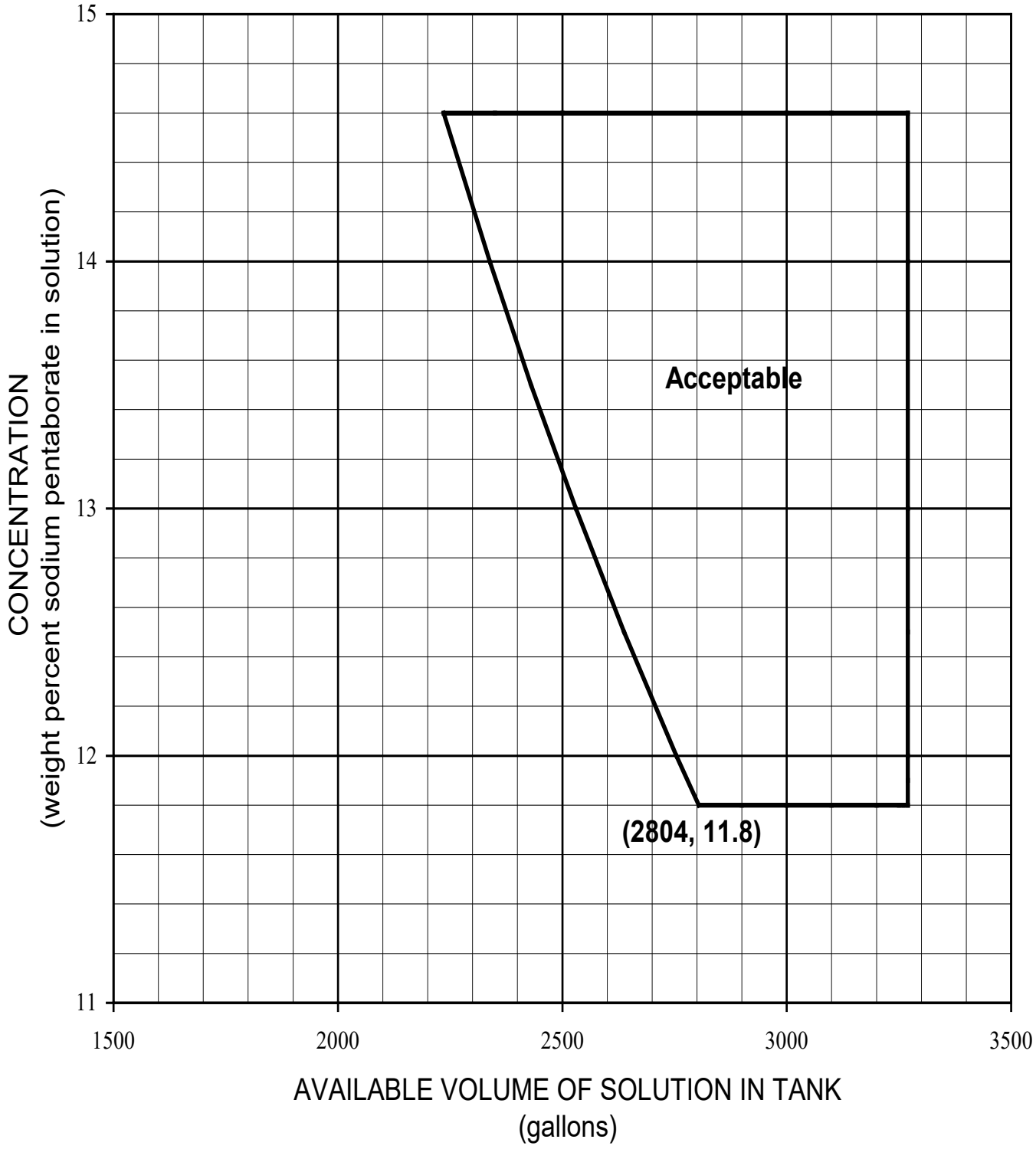

Figure 3.1.7-1 (page 1 of 1)
Sodium Pentaborate Solution Volume
Versus Concentration Requirements

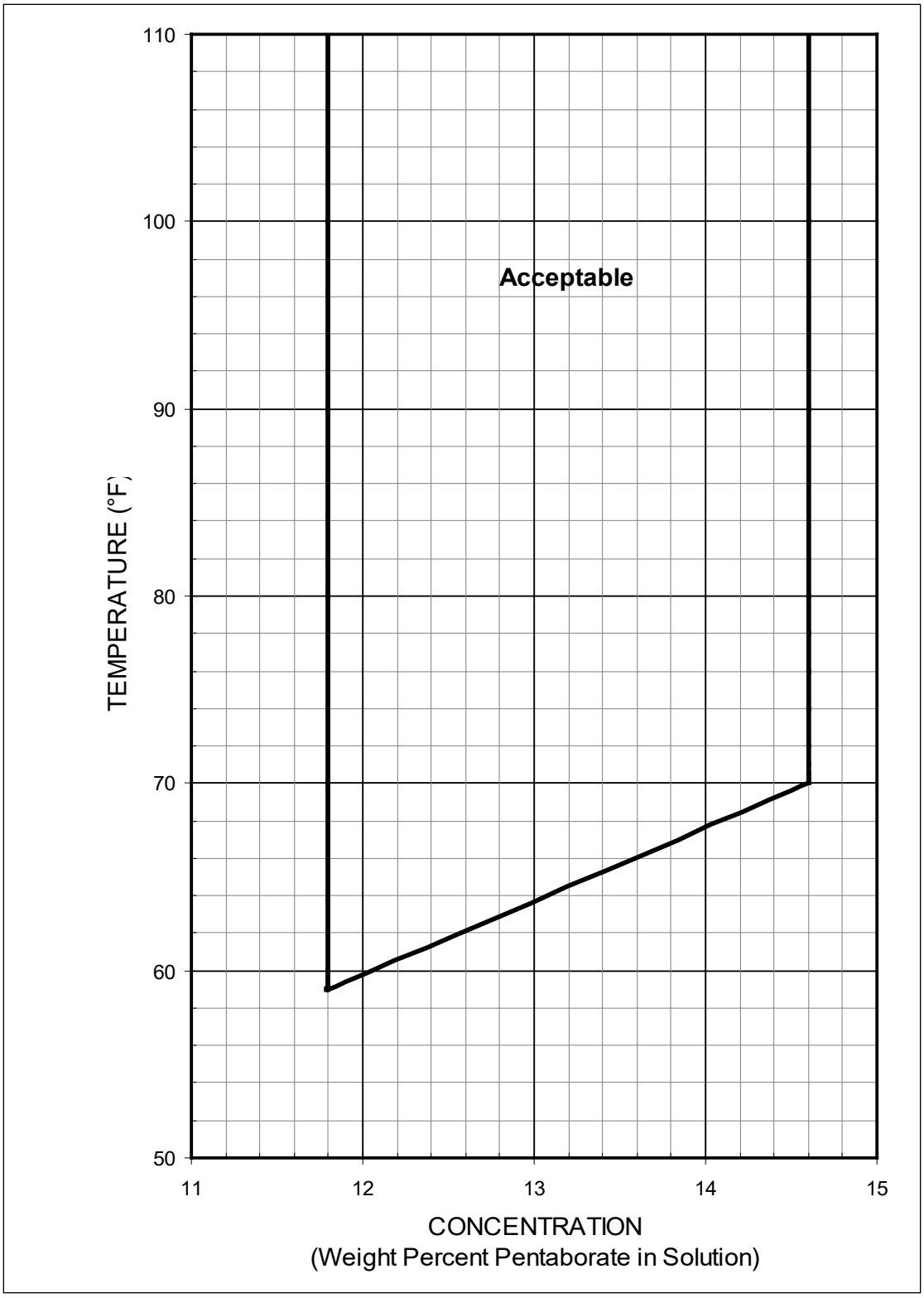

Figure 3.1.7-2 (page 1 of 1)
Sodium Pentaborate Solution Temperature Versus Concentration Requirements

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

LCO 3.1.8 Each SDV vent and drain valve shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

1. Separate Condition entry is allowed for each SDV vent and drain line.
2. An isolated line may be unisolated under administrative control to allow draining and venting of the SDV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SDV vent or drain lines with one valve inoperable.	A.1 Isolate the associated line.	7 days
B. One or more SDV vent or drain lines with both valves inoperable.	B.1 Isolate the associated line.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	----------NOTE---------- Not required to be met on vent and drain valves closed during the performance of SR 3.1.8.2. ---------- Verify each SDV vent and drain valve is open.	In accordance with the Surveillance Frequency Control Program
SR 3.1.8.2	Cycle each SDV vent and drain valve to the fully closed and fully open position.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.1.8.3	Verify each SDV vent and drain valve: a. Closes in $\leq$ 30 seconds after receipt of an actual or simulated scram signal; and b. Opens when the actual or simulated scram signal is reset.	In accordance with the Surveillance Frequency Control Program

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER $\geq$ 21.7% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.7% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after $\geq$ 21.7% RTP AND In accordance with the Surveillance Frequency Control Program

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 21.7% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.7% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 21.7% RTP AND In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 AND Once within 72 hours after each completion of SR 3.1.4.2.

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 2.	8 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 21.7% RTP. ---------- Verify the absolute difference between the Average Power Range Monitor (APRM) channels and the calculated power is ≤ 2% RTP plus any gain adjustment required by LCO 3.4.1, “Recirculation Loops Operating,” while operating at ≥ 21.7% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	Perform a functional test of each automatic scram contactor.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.4	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	Verify the Source Range Monitor (SRM) and Intermediate Range Monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.7	----------NOTE---------- Only required to be met during entry into MODE 2 from MODE 1. ---------- Verify the IRM and APRM channels overlap.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.8	Calibrate the local power range monitors.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.10	Calibrate the trip units.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.13	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.14	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.16	Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.17	Adjust the channel to conform to a calibrated flow signal.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.19	Verify the RPS logic system response time is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux - High	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 125/125 divisions of full scale
	5[(a)]	2	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 125/125 divisions of full scale
b. Inop	2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.15 SR 3.3.1.1.19	NA
	5[(a)]	2	H	SR 3.3.1.1.5 SR 3.3.1.1.15 SR 3.3.1.1.19	NA
2. Average Power Range Monitors					
a. Neutron Flux - Upscale, Startup	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 16.6% RTP
b. Flow Biased - High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.19	$\leq$ (0.55W + 67.7) [(b) (c)]

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) When reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating," the following Allowable Value applies:

$\leq$ (0.55W + 61.4) [(c)]

The trip setpoints may be reset by adjusting APRM gain or by recalibrating the APRMs.

(c) W is equal to the percentage of the drive flow, where 100% drive flow is that required to achieve 100% core flow at 100% RTP.

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. High Value Clamp	1	2	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 121.6% RTP
d. Inop	1,2	2	G	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.19	NA
3. Reactor Vessel Steam Dome Pressure - High	1,2	2	G	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.15 SR 3.3.1.1.18 SR 3.3.1.1.19	$\leq$ 1069.2 psig
4. Reactor Vessel Water Level - Low	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.18 SR 3.3.1.1.19	$\geq$ 165.6 inches
5. Main Steam Isolation Valve - Closure	1	4	F	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 10% closed
6. Drywell Pressure - High	1,2	2	G	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 2.2 psig

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level - High					
a. Resistance Temperature Detector	1,2	2	G	SR 3.3.1.1.3 SR 3.3.1.1.10 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 769 ft – 3.0 inches
	5[(a)]	2	H	SR 3.3.1.1.3 SR 3.3.1.1.10 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 769 ft – 3.0 inches
b. Float Switch	1,2	2	G	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 769 ft – 2.8 inches
	5[(a)]	2	H	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.19	$\leq$ 769 ft – 2.8 inches
8. Turbine Stop Valve - Closure	$\geq$ 26% RTP	4	E	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.19	$\leq$ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	$\geq$ 26% RTP	2	E	SR 3.3.1.1.3 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.19	$\geq$ 465 psig
10. Reactor Mode Switch – Shutdown Position	1,2	1	G	SR 3.3.1.1.13 SR 3.3.1.1.15	NA
	5[(a)]	1	H	SR 3.3.1.1.13 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.9 SR 3.3.1.1.15	NA
	5[(a)]	1	H	SR 3.3.1.1.9 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.1.2 Source Range Monitor (SRM) Instrumentation

LCO 3.3.1.2 The SRM instrumentation in Table 3.3.1.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.2-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRMs inoperable in MODE 2 with Intermediate Range Monitors (IRMs) on Range 2 or below.	A.1 Restore required SRMs to OPERABLE status.	4 hours
B. Three required SRMs inoperable in MODE 2 with IRMs on Range 2 or below.	B.1 Suspend control rod withdrawal.	Immediately
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more required SRMs inoperable in MODE 3 or 4.	D.1 Fully insert all insertable control rods. AND D.2 Place reactor mode switch in the shutdown position.	1 hour 1 hour
E. One or more required SRMs inoperable in MODE 5.	E.1 Suspend CORE ALTERATIONS except for control rod insertion. AND E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.1.2-1 to determine which SRs apply for each applicable MODE or other specified conditions.

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.2	----------NOTES---------- 1. Only required to be met during CORE ALTERATIONS. 2. One SRM may be used to satisfy more than one of the following. --- Verify an OPERABLE SRM detector is located in : a. The fueled region; b. The core quadrant where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region; and c. A core quadrant adjacent to where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.3	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.4	----------NOTE---------- Not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies in the associated core quadrant. ---------- Verify count rate is $\geq$ 3.0 cps.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.6	----------NOTE---------- Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.7	----------NOTES---------- 1. Neutron detectors are excluded. 2. Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

Table 3.3.1.2-1 (page 1 of 1)
Source Range Monitor Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS
1. Source Range Monitor	2[a]	3	SR 3.3.1.2.1 SR 3.3.1.2.4 SR 3.3.1.2.6 SR 3.3.1.2.7
	3,4	2	SR 3.3.1.2.3 SR 3.3.1.2.4 SR 3.3.1.2.6 SR 3.3.1.2.7
	5	2[b] [c]	SR 3.3.1.2.1 SR 3.3.1.2.2 SR 3.3.1.2.4 SR 3.3.1.2.5 SR 3.3.1.2.7

(a) With IRMs on Range 2 or below.

(b) Only one SRM channel is required to be OPERABLE during spiral offload or reload when the fueled region includes only that SRM detector.

(c) Special movable detectors may be used in place of SRMs if connected to normal SRM circuits.

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

LCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Rod Block Monitor (RBM) channel inoperable.	A.1 Restore RBM channel to OPERABLE status.	24 hours
B. Required Action and associated Completion Time of Condition A not met. OR Two RBM channels inoperable.	B.1 Place one RBM channel in trip.	1 hour
C. Rod Worth Minimizer (RWM) inoperable during reactor startup.	C.1 Suspend control rod movement except by scram. OR	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.1 Verify ≥ 12 rods withdrawn. OR C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year. AND C.2.2 Verify movement of control rods is in compliance with Banked Position Withdrawal Sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	Immediately Immediately During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more Reactor Mode Switch – Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal. AND	Immediately
	E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.2.1-1 to determine which SRs apply for each Control Rod Block Function.

2. When an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.3	----------NOTE---------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 10 % RTP in MODE 1. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.4	----------NOTE---------- Neutron detectors are excluded. ---------- Verify the RBM: a. Low Power Range – Upscale Function is not bypassed when THERMAL POWER is ≥ 29% and < 64% RTP. b. Intermediate Power Range – Upscale Function is not bypassed when THERMAL POWER is ≥ 64% and < 84% RTP. c. High Power Range – Upscale Function is not bypassed when THERMAL POWER is ≥ 84% RTP.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.5	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.6	----------NOTE---------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.7	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range - Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5	$\leq$ 115.5/125 divisions of full scale
b. Intermediate Power Range - Upscale	(b)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5	$\leq$ 109.7/125 divisions of full scale
c. High Power Range – Upscale	(c),(d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5	$\leq$ 105.9/125 divisions of full scale
d. Inop	(d),(e)	2	SR 3.3.2.1.1	NA
e. Downscale	(d),(e)	2	SR 3.3.2.1.1 SR 3.3.2.1.5	NA
f. Bypass Time Delay	(d),(e)	2	SR 3.3.2.1.1 SR 3.3.2.1.5	$\leq$ 2.0 seconds
2. Rod Worth Minimizer	1[(f)],2[(f)]	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.7	NA
3. Reactor Mode Switch – Shutdown Position	(g)	2	SR 3.3.2.1.6	NA

(a) THERMAL POWER $\geq$ 30% and $<$ 65% RTP and MCPR less than the limit specified in the COLR.

(b) THERMAL POWER $\geq$ 65% and $<$ 85% RTP and MCPR less than the limit specified in the COLR.

(c) THERMAL POWER $\geq$ 85% and $<$ 90% RTP and MCPR less than the limit specified in the COLR.

(d) THERMAL POWER $\geq$ 90% RTP and MCPR less than the limit specified in the COLR.

(e) THERMAL POWER $\geq$ 30% and $<$ 90% RTP and MCPR less than the limit specified in the COLR.

(f) With THERMAL POWER $\leq$ 10% RTP, except during the reactor shutdown process if the coupling of each withdrawn control rod has been confirmed.

(g) Reactor mode switch in the shutdown position.

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each Function. For Function 6, Separate Condition entry is allowed for each penetration flow path.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.6.	Immediately
C. One or more Functions with two required channels inoperable.	C.1 Restore one required channel to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	E.1 Be in MODE 3.	12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	F.1 Initiate action in accordance with Specification 5.6.6.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
These SRs apply to each Function in Table 3.3.3.1-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1. Reactor Steam Dome Pressure	2	E
2. Reactor Vessel Water Level		
a. Wide Range	2	E
b. Fuel Zone	2	E
3. Suppression Pool Water Level	2	E
4. Drywell Pressure		
a. Narrow Range	2	E
b. Wide Range	2	E
5. Primary Containment Area Radiation		
a. Drywell	2	F
b. Suppression Chamber	2	F
6. PCIV Position	2 per penetration flow path [(a)(b)]	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

3.3 INSTRUMENTATION

3.3.3.2 Remote Shutdown System

LCO 3.3.3.2 The Remote Shutdown System Functions shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable.	A.1 Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.1	Verify each required control circuit and transfer switch is capable of performing the intended function.	In accordance with the Surveillance Frequency Control Program
SR 3.3.3.2.2	Perform CHANNEL CALIBRATION for each required instrumentation channel.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV) – Closure; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure-Low.

OR

b. LCO 3.2.2 “MINIMUM CRITICAL POWER RATIO (MCPR),” limits for inoperable EOC-RPT as specified in the COLR are made applicable.

APPLICABILITY: THERMAL POWER ≥ 26% RTP.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR A.2 ----------NOTE---------- Not applicable if inoperable channel is the result of an inoperable breaker. ---------- Place channel in trip.	72 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR limit for inoperable EOC-RPT not made applicable.	B.1 Restore EOC-RPT trip capability. OR B.2 Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours 2 hours
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump from service. OR C.2 Reduce THERMAL POWER to < 26% RTP.	4 hours 4 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV – Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure – Low: ≥ 465 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.4	Verify TSV – Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26 % RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.5	Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

LCO 3.3.4.2 Two channels in a trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level – Low Low; and

b. Reactor Steam Dome Pressure – High.

APPLICABILITY: MODE 1.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function with one or more channels inoperable.	A.1 Restore ATWS-RPT trip capability.	72 hours
B. Both Functions with ATWS-RPT trip capability not maintained.	B.1 Restore ATWS-RPT trip capability for one Function.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump from service. OR C.2 Be in MODE 2.	8 hours 8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.1	Perform CHANNEL CHECK on the Reactor Vessel Water Level – Low Low Function.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level – Low Low: ≥ 112.65 inches; and b. Reactor Steam Dome Pressure – High: ≤ 1154.2 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

LCO 3.3.5.1 The ECCS instrumentation for each Function in Table 3.3.5.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5.1-1.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.1-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.1-1	B.1 ----------NOTE---------- Only applicable for Functions 1.a, 1.b, 2.a, and 2.b. ---------- Declare supported feature(s) inoperable when redundant feature(s) ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in two or more low pressure ECCS subsystems
	AND	
	B.2 ----------NOTE---------- Only applicable for Functions 3.a and 3.b. ---------- Declare High Pressure Coolant Injection (HPCI) System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND	
	B.3 Place channel in trip.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1 ----------NOTE---------- Only applicable for Functions 1.c, 1.e, 2.c and 2.e. ---------- Declare supported feature(s) inoperable.	1 hour from discovery of loss of initiation capability for two or more low pressure ECCS subsystems
	AND	
	C.2 ----------NOTE-------- Only applicable for Functions 2.g, 2.h, 2.i, and 2.j. ---------- Declare Low Pressure Coolant Injection (LPCI) subsystem inoperable.	1 hour from discovery of loss of Loop Selection capability
	AND	
	C.3 Restore channel to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1 ----------NOTE---------- Only applicable if HPCI pump suction is not aligned to the suppression pool. ---------- Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI suction transfer capability
	AND	
	D.2.1 Place channel in trip.	24 hours
	OR	
	D.2.2 Align the HPCI pump suction to the suppression pool.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 ----------NOTE---------- Only applicable for Functions 1.d and 2.f. ---------- Declare supported feature(s) inoperable.	1 hour from discovery of loss of initiation capability for two or more minimum flow valves in the low pressure ECCS subsystems
	AND	
	E.2 Restore channel to OPERABLE status.	7 days
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1 Restore channel to OPERABLE status.	1 hour
G. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	G.1 Declare Automatic Depressurization System (ADS) valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip logics
	AND	
	G.2 Place channel in trip.	96 hours from discovery of inoperable channel concurrent with HPCI or Reactor Core Isolation Cooling (RCIC) inoperable AND 8 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	H.1 Declare ADS valves inoperable. AND H.2 Restore channel to OPERABLE status.	1 hour from discovery of loss of ADS initiation capability in both trip logics 96 hours from discovery of inoperable channel concurrent with HPCI or RCIC inoperable AND 8 days
I. Required Action and associated Completion Time of Condition B, C, D, E, F, G, or H not met.	I.1 Declare associated supported feature(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 1.d, 2.f, 3.c, 3.d, 3.e, and 3.f; and (b) for up to 6 hours for Functions other than 1.d, 2.f, 3.c, 3.d, 3.e, and 3.f provided the associated Function (or the redundant Function for Functions 4 and 5) maintains ECCS initiation or loop selection capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.3	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.6	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.8	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.9	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.1-1 (page 1 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Core Spray System					
a. Reactor Vessel Water Level – Low Low Low	1,2,3,	4[(a)]	B	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 38.3 inches
b. Drywell Pressure - High	1,2,3	4[(a)]	B	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\leq$ 2.19 psig
c. Reactor Steam Dome Pressure – Low (Injection Permissive)	1,2,3	4	C	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 363.3 psig and $\leq$ 485.1 psig
d. Core Spray Pump Discharge Flow – Low (Bypass)	1,2,3	1 per pump	E	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 256.6 gpm and $\leq$ 2382.1 gpm
e. Core Spray Pump Start Time Delay Relay	1,2,3	1 per pump	C	SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 2.6 seconds and $\leq$ 6.8 seconds
f. 4.16 kV Emergency Bus Sequential Loading Relay	1,2,3	1 per pump	F	SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.9	$\leq$ 3500 V
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Vessel Water Level- Low Low Low	1,2,3	4	B	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 38.3 inches
b. Drywell Pressure - High	1,2,3	4	B	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\leq$ 2.19 psig

(a) Also required to initiate the associated Diesel Generator (DG).

Table 3.3.5.1-1 (page 2 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI System (continued)					
c. Reactor Steam Dome Pressure – Low (Injection Permissive)	1,2,3	4	C	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 363.3 psig and $\leq$ 485.1 psig
d. Reactor Vessel Shroud Level - Low	1,2,3	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.9	$\geq$ -40.89 inches
e. Low Pressure Coolant Injection Pump Start - Time Delay Relay	1,2,3	1 per pump	C	SR 3.3.5.1.8 SR 3.3.5.1.9	
Pumps A & B					$\geq$ 8.8 seconds and $\leq$ 11.2 seconds
Pumps C & D					$\geq$ 13.8 seconds and $\leq$ 33.5 seconds
f. Low Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	1,2,3	1 per loop	E	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 471.8 gpm and $\leq$ 3676.6 gpm
g. LPCI Loop Select-Reactor Vessel Water Level - Low-Low	1,2,3	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.6 SR 3.3.5.1.9	$\geq$ 112.65 inches
h. LPCI Loop Select – Reactor Steam Dome Pressure - Low	1,2,3	4	C	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.9	$\geq$ 887 psig

Table 3.3.5.1-1 (page 3 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI System (continued)					
i. LPCI Loop Select – Recirculation Pump Differential Pressure	1,2,3	4 per pump	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.8 SR 3.3.5.1.9	$\leq$ 7.8 psid
j. LPCI Loop Select – Recirculation Riser Differential Pressure	1,2,3	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.9	$\geq$ 0.13 psid and $\leq$ 2.07 psid
k. 4.16 kV Emergency Bus Sequential Loading Relay	1,2,3	2	F	SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.9	$\leq$ 3500 V
3. High Pressure Coolant Injection (HPCI) System					
a. Reactor Vessel Water Level - Low Low	1, 2(b), 3(b)	4	B	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.6 SR 3.3.5.1.9	$\geq$ 112.65 inches
b. Drywell Pressure - High	1, 2(b), 3(b)	4	B	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\leq$ 2.19 psig
c. Reactor Vessel Water Level - High	1, 2(b), 3(b)	2	C	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.6 SR 3.3.5.1.9	$\leq$ 214.8 inches
d. Condensate Storage Tank Level - Low	1, 2(b), 3(b)	2	D	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	$\geq$ 11.6 inches

(b) With reactor steam dome pressure > 150 psig.

Table 3.3.5.1-1 (page 4 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. HPCI System (continued)					
e. Suppression Pool Water Level – High	1, 2[(b)], 3[(b)]	2	D	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 5.9 inches
f. High Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	1, 2[(b)], 3[(b)]	1	E	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 264.2 gpm and ≤ 2025.1 gpm
4. Automatic Depressurization System (ADS) Trip Logic A					
a. Reactor Vessel Water Level - Low Low Low	1, 2[(c)], 3[(c)]	2	G	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 38.3 inches
b. Automatic Depressurization System Timer	1, 2[(c)], 3[(c)]	1	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 125 seconds
c. Reactor Vessel Water Level – Low (Confirmatory)	1, 2[(c)], 3[(c)]	1	G	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 166.1 inches
d. Core Spray Pump Discharge Pressure - High	1, 2[(c)], 3[(c)]	2	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 114.2 psig and ≤ 177.0 psig
e. Low Pressure Coolant Injection Pump Discharge Pressure - High	1, 2[(c)], 3[(c)]	4	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 103.8 psig and ≤ 147.0 psig

(b) With reactor steam dome pressure > 150 psig.

(c) With reactor steam dome pressure > 100 psig.

Table 3.3.5.1-1 (page 5 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. ADS Trip Logic B					
a. Reactor Vessel Water Level - Low Low Low	1, 2(c), 3(c)	2	G	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 38.3 inches
b. Automatic Depressurization System Timer	1, 2(c), 3(c)	1	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 125 seconds
c. Reactor Vessel Water Level – Low (Confirmatory)	1, 2(c), 3(c)	1	G	SR 3.3.5.1.1 SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 166.1 inches
d. Core Spray Pump Discharge Pressure - High	1, 2(c), 3(c)	2	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 114.2 psig and ≤ 177.0 psig
e. Low Pressure Coolant Injection Pump Discharge Pressure – High	1, 2(c), 3(c)	4	H	SR 3.3.5.1.3 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 103.8 psig and ≤ 147.0 psig

(c) With reactor steam dome pressure > 100 psig.

3.3 INSTRUMENTATION

3.3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control Instrumentation

LCO 3.3.5.2 The RPV Water Inventory Control instrumentation for each Function in Table 3.3.5.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5.2-1

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.2-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	B.1 Declare associated penetration flow path(s) incapable of automatic isolation. AND B.2 Calculate DRAIN TIME.	Immediately Immediately
C. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	C.1 Place Channel in trip.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	D.1 Restore channel to OPERABLE status.	24 hours
E. Required Action and associated Completion Time of Condition C or D not met.	E.1 Declare associated ECCS injection/spray subsystem inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTES----------
Refer to Table 3.3.5.2-1 to determine which SRs apply for each ECCS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.2-1 (page 1 of 1)
RPV Water Inventory Control Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Core Spray System					
a. Reactor Steam Dome Pressure – Low (Injection Permissive)	4, 5	4	C	SR 3.3.5.2.2	$\leq$ 485.1 psig
b. Core Spray Pump Discharge Flow – Low (Bypass)	4, 5	1 per Pump[(a)]	D	SR 3.3.5.2.2	$\geq$ 256.6 gpm and $\leq$ 2382.1 gpm
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Steam Dome Pressure – Low (Injection Permissive)	4, 5	4	C	SR 3.3.5.2.2	$\leq$ 485.1 psig
b. Low Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	4, 5	1 per loop[(a)]	D	SR 3.3.5.2.2	$\geq$ 471.8 gpm and $\leq$ 3676.6 gpm
3. RHR System Isolation					
a. Reactor Vessel Water Level – Low	(b)	2 in one trip system	B	SR 3.3.5.2.1 SR 3.3.5.2.2	$\geq$ 165.6 inches
4. Reactor Water Cleanup (RWCU) System Isolation					
a. Reactor Vessel Water Level – Low Low	(b)	2 in one trip system	B	SR 3.3.5.2.1 SR 3.3.5.2.2	$\geq$ 112.65 inches

(a) Associated with an ECCS subsystem required to be OPERABLE by LCO 3.5.2, “Reactor Pressure Vessel Water Inventory Control.”

(b) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.3 The RCIC System instrumentation for each Function in Table 3.3.5.3-1 shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1 Declare RCIC System inoperable. AND B.2 Place channel in trip.	1 hour from discovery of loss of RCIC initiation capability 24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	C.1 Restore channel to OPERABLE status.	24 hours
D. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	D.1 ----------NOTE---------- Only applicable if RCIC pump suction is not aligned to the suppression pool. ---------- Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC suction transfer capability
	AND	
	D.2.1 Place channel in trip.	24 hours
	OR	
	D.2.2 Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1 Declare RCIC System inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.3-1 to determine which SRs apply for each RCIC Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 2 and 3; and (b) for up to 6 hours for Function 1 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.3-1 (page 1 of 1)
Reactor Core Isolation Cooling System Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low Low	4	B	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	$\geq$ 112.65 inches
2. Reactor Vessel Water Level - High	2	C	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	$\leq$ 214.8 inches
3. Condensate Storage Tank Level - Low	2	D	SR 3.3.5.3.2 SR 3.3.5.3.4 SR 3.3.5.3.5	$\geq$ 11.6 inches

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.b, 6.b, and 6.c AND 24 hours for Functions other than Functions 2.a, 2.b, and 6.b, and 6.c
	AND	
	A.2 ----------NOTE--------- Only applicable for Function 7.a. ---------- Inhibit containment spray system.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
G. [Deleted]		
H. As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time for Condition F not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 4.	12 hours 36 hours
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 Declare Standby Liquid Control (SLC) System inoperable. OR I.2 Isolate the Reactor Water Cleanup System.	1 hour 1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	J.1 Initiate action to restore channel to OPERABLE status. OR J.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System.	Immediately Immediately
K. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	K.1 ----------NOTE---------- Only applicable if inoperable channel is not in trip. ---------- Declare associated Suppression Pool Cooling/Spray subsystem(s) inoperable. OR K.2 ----------NOTE---------- Only applicable if inoperable channel is in trip. ---------- Declare Primary Containment inoperable.	 Immediately Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	L.1 Isolate the primary containment vent and purge penetration flow paths. OR L.2 Establish administrative control of the primary containment vent and purge valves using continuous monitoring of alternate instrumentation.	1 hour 1 hour

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 5.a; and (b) for up to 6 hours for Functions other than 5.a provided the associated Function maintains isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.2	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.3	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.4	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.6	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.8	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.9	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.1-1 (page 1 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low Low	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 38.3 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.9	$\geq$ 821 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.9	$\leq$ 138% rated steam flow
d. Condenser Backpressure - High	1, 2[(a)], 3[(a)]	2	D	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 7.2 inches Hg vacuum
e. Main Steam Line Tunnel Temperature - High	1,2,3	4	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7 SR 3.3.6.1.9	$\leq$ 205.1°F
f. Turbine Building Temperature - High	1,2,3	4	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7 SR 3.3.6.1.9	$\leq$ 205.1°F

(a) When any turbine stop valve is greater than 90% open or when the key-locked bypass switch is in the NORM Position.

Table 3.3.6.1-1 (page 2 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 165.6 inches
b. Drywell Pressure - High	1,2,3	2	H	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 2.2 psig
c. Offgas Vent Stack -High Radiation	1[(c)], 2[(c)], 3[(c)]	1	L	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	(b)
d. Reactor Building Exhaust Shaft – High Radiation	1,2,3	1	H	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 12.8 mR/hr
e. Refueling Floor Exhaust Duct – High Radiation	1,2,3	1	H	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 10.6 mR/hr
3. High Pressure Coolant Injection (HPCI) System Isolation					
a. HPCI Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 409 inches (inboard) $\leq$ 110 inches (outboard)

(b) Allowable value is determined in accordance with the ODAM.

(c) During venting or purging of primary containment.

Table 3.3.6.1-1 (page 3 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. HPCI System Isolation (continued)					
b. HPCI Steam Supply Line Pressure – Low	1,2,3	2	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 50 psig and $\leq$ 147.1 psig
c. HPCI Turbine Exhaust Diaphragm Pressure – High	1,2,3	2	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 2.5 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 2.2 psig
e. Suppression Pool Area Ambient Temperature – High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 153.3°F
f. HPCI Leak Detection Time Delay	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	N/A
g. Suppression Pool Area Ventilation Differential Temperature – High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 51.5°F
h. HPCI Equipment Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 178.3°F
i. HPCI Room Ventilation Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 51.5°F

Table 3.3.6.1-1 (page 4 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Reactor Core Isolation Cooling (RCIC) System Isolation					
a. RCIC Steam Line Flow – High	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 164 inches (inboard) ≤ 159 inches (outboard)
b. RCIC Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≥ 50.3 psig
c. RCIC Turbine Exhaust Diaphragm Pressure – High	1,2,3	2	F	SR 3.3.6.1.4 SR 3.3.6.1.6 SR 3.3.6.1.9	≥ 3.3 psig
d. Drywell Pressure – High	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 2.2 psig
e. RCIC Suppression Pool Area Ambient Temperature - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 153.3°F
f. RCIC Leak Detection Time Delay	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	N/A
g. RCIC Suppression Pool Area Ventilation Differential Temperature – High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 51.5°F
h. RCIC Equipment Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 178.3°F
i. RCIC Room Ventilation Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 51.5°F

Table 3.3.6.1-1 (page 5 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Reactor Water Cleanup (RWCU) System Isolation					
a. Differential Flow - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 59 gpm
b. Area Temperature - High	1,2,3	1[(d)]	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 133.3°F
c. Area Ventilation Differential Temperature – High	1,2,3	1[(d)]	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	
RWCU Pump Room					≤ 22.5°F
RWCU Pump A Room					≤ 23.5°F
RWCU Pump B Room					≤ 34.5°F
RWCU Heat Exch. Room					≤ 51.5°F
d. SLC System Initiation	1,2	1[(e)]	I	SR 3.3.6.1.9	NA
e. Reactor Vessel Water Level – Low Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.4 SR 3.3.6.1.7 SR 3.3.6.1.9	≥ 112.6 5 inches
f. Area Near TIP Room Ambient Temperature – High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	≤ 115.7°F

(d) Each Trip System must have either an OPERABLE Function 5.b or an OPERABLE Function 5.c channel in both the RWCU pump area and in the RWCU heat exchanger area.

(e) SLC System Initiation only inputs into one of the two trip systems.

Table 3.3.6.1-1 (page 6 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
6. Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.9	$\leq$ 152.7 psig
b. Reactor Vessel Water Level – Low	3	2	J	SR 3.3.6.1.1 SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 165.6 inches
c. Drywell Pressure – High	1,2,3	2	F	SR 3.3.6.1.4 SR 3.3.6.1.8 SR 3.3.6.1.9	$\leq$ 2.2 psig
7. Containment Cooling System Isolation					
a. Containment Pressure – High	1,2,3	4	K	SR 3.3.6.1.3 SR 3.3.6.1.8 SR 3.3.6.1.9	$\geq$ 1.25 psig

3.3 INSTRUMENTATION

3.3.6.2 Secondary Containment Isolation Instrumentation

LCO 3.3.6.2 The secondary containment isolation instrumentation for each Function in Table 3.3.6.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.2-1.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 1 and 2 AND 24 hours for Functions 3 and 4
B. One or more Functions with secondary containment isolation capability not maintained.	B.1 Restore secondary containment isolation capability.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1.1 Isolate secondary containment. OR	1 hour
	C.1.2 Declare associated Secondary Containment Isolation Valves/Dampers (SCIV/Ds) inoperable. AND	1 hour
	C.2.1 Place the associated Standby Gas Treatment (SBGT) subsystem(s) in operation. OR	1 hour
	C.2.2 Declare associated SBGT subsystem(s) inoperable.	1 hour

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.2-1 to determine which SRs apply for each Secondary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains secondary containment isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.2	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.3	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.2-1 (page 1 of 1)
Secondary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level - Low	1,2,3	2	SR 3.3.6.2.1 SR 3.3.6.2.3 SR 3.3.6.2.4 SR 3.3.6.2.5	$\geq$ 165.6 inches
2. Drywell Pressure - High	1,2,3	2	SR 3.3.6.2.3 SR 3.3.6.2.4 SR 3.3.6.2.5	$\leq$ 2.2 psig
3. Reactor Building Exhaust Shaft – High Radiation	1,2,3	1	SR 3.3.6.2.2 SR 3.3.6.2.3 SR 3.3.6.2.4 SR 3.3.6.2.5	$\leq$ 12.8 mR/hr
4. Refueling Floor Exhaust Duct – High Radiation	1,2,3	1	SR 3.3.6.2.2 SR 3.3.6.2.3 SR 3.3.6.2.4 SR 3.3.6.2.5	$\leq$ 10.6 mR/hr

3.3 INSTRUMENTATION

3.3.6.3 Low-Low Set (LLS) Instrumentation

LCO 3.3.6.3 The LLS valve instrumentation for each Function in Table 3.3.6.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LLS valve inoperable due to inoperable channel(s).	A.1 Restore channel(s) to OPERABLE status.	24 hours
B. One or more Safety Relief Valves (SRVs) with one Function 3 channel inoperable.	B.1 Restore channel(s) to OPERABLE status.	Prior to entering MODE 2 or 3 from MODE 4
C. ----------NOTE---------- Separate Condition entry is allowed for each SRV. ---------- One or more SRVs with two or more Function 3 channels inoperable.	C.1 Restore at least two channels per SRV to OPERABLE status.	14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met. OR Both LLS valves inoperable due to inoperable channels.	D.1 Declare the associated LLS valve(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.3-1 to determine which SRs apply for each Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.1	Perform CHANNEL FUNCTIONAL TEST for portion of the channel outside primary containment.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.5	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.3-1 (page 1 of 1)
Low-Low Set Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Steam Dome Pressure - High	1 per LLS valve	SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.6	$\leq$ 1069.21 psig
2. Low-Low Set Pressure Setpoints	2 per LLS valve	SR 3.3.6.3.2 SR 3.3.6.3.4 SR 3.3.6.3.6	Low: Open $\geq$ 1014 psig and $\leq$ 1045 psig Close $\geq$ 893.4 psig and $\leq$ 925 psig High: Open $\geq$ 1019 psig and $\leq$ 1050 psig Close $\geq$ 893.4 psig and $\leq$ 930 psig
3. Tailpipe High Pressure	3 per SRV	SR 3.3.6.3.1 SR 3.3.6.3.5 SR 3.3.6.3.6	$\leq$ 99 psig

3.3 INSTRUMENTATION

3.3.7.1 Standby Filter Unit (SFU) System Instrumentation

LCO 3.3.7.1 Two channels of the Control Building Intake Area Radiation – High Function shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both channels inoperable.	A.1 Declare associated SFU subsystem(s) inoperable. OR A.2 Place associated SFU subsystem(s) in the isolation mode.	1 hour 1 hour

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other channel is OPERABLE.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.3	Perform CHANNEL CALIBRATION. The Allowable Value shall be $\leq$ 5 mR/hr.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated Diesel Generator is required to be OPERABLE by LCO 3.8.2, “AC Sources – Shutdown.”

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each channel.

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or more Function 1 or 3 channels inoperable.	A.1	Place channel in trip.	1 hour
B.	One or more Function 2 channels inoperable.	B.1	Declare associated Diesel Generator (DG) inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in one or both divisions
		AND		
		B.2	Place channel in trip.	24 hours
C.	Required Action and associated Completion Time not met.	C.1	Declare associated DG inoperable.	Immediately

(continued)

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	1	SR 3.3.8.1.2 SR 3.3.8.1.4 SR 3.3.8.1.5	≥ 595 V and ≤ 2275 V
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)			
a. Bus Undervoltage	4	SR 3.3.8.1.1 SR 3.3.8.1.3 SR 3.3.8.1.5	≥ 3780 V and ≤3822 V
b. Time Delay	4	SR 3.3.8.1.1 SR 3.3.8.1.3 SR 3.3.8.1.5	≥ 7.92 seconds and ≤ 8.5 seconds
3. 4.16 kV Emergency Transformer Supply Undervoltage	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.5	≥ 2450 V

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS Electrical Protection Assemblies (EPAs) shall be OPERABLE for each inservice RPS motor generator set or alternate power supply.

APPLICABILITY: MODES 1 and 2,
MODES 3, 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both inservice power supplies with one EPA inoperable.	A.1 Remove associated inservice power supply(s) from service.	72 hours
B. One or both inservice power supplies with both EPAs inoperable.	B.1 Remove associated inservice power supply(s) from service.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1 or 2.	C.1 Be in MODE 3.	12 hours
D. Required Action and associated Completion Time of Condition A or B not met in MODE 3, 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	----------NOTE---------- Only required to be performed prior to entering MODE 2 or 3 from MODE 4, when in MODE 4 for ≥ 24 hours. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage ≤ 132 V. b. Undervoltage ≥ 108 V. c. Underfrequency ≥ 57 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.2.3	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Recirculation Loops Operating

LCO 3.4.1 Two recirculation loops with matched pump speeds shall be in operation with core flow as a function of THERMAL POWER outside the Exclusion Region specified in the COLR.

OR

One recirculation loop may be in operation with core flow as a function of THERMAL POWER outside the Exclusion Region specified in the COLR and with the following limits applied when the associated LCO is applicable:

a. LCO 3.2.1, “AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR),” single loop operation limits specified in the COLR;

b. LCO 3.2.2, “MINIMUM CRITICAL POWER RATIO (MCPR),” single loop operation limits specified in the COLR; and

c. LCO 3.3.1.1, “Reactor Protection System (RPS) Instrumentation,” Function 2.b (Average Power Range Monitors Flow Biased High Scram), Allowable Value of Table 3.3.1.1-1 is reset for single loop operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. No recirculation loops in operation.	A.1 Place the reactor mode switch in the Shutdown position.	Immediately
B. One or two recirculation loops in operation in the Exclusion Region of the power/flow map described in the Core Operating Limits Report.	B.1 Initiate action to exit the Exclusion Region.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or two recirculation loops in operation in the Exclusion Region of the power/flow map described in the Core Operating Limits Report.	C.1 Initiate action to exit the Exclusion Region.	Immediately
D. Recirculation pump speed mismatch not within limits.	C.1 Trip one recirculation pump.	2 hours
E. Requirements of the LCO not met for reasons other than Conditions A, B or C.	D.1 Satisfy requirements of the LCO.	24 hours
F. Required Action and associated Completion Time of Condition C or D not met.	E.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	----------NOTE---------- Not required to be performed until 24 hours after both recirculation loops are in operation. ---------- Verify recirculation pump speed mismatch with both recirculation pumps at steady state operation is as follows: a. The speed of the faster pump shall be ≤ 135% of the speed of the slower pump when operating at < 69.4 % RTP. b. The speed of the faster pump shall be ≤ 122% of the speed of the slower pump when operating at ≥ 69.4 % RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.2	Verify core flow as a function of core THERMAL POWER is outside the Exclusion Region shown in the COLR.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Jet Pumps

LCO 3.4.2 All jet pumps shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more jet pumps inoperable.	A.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	----------NOTES---------- 1. Not required to be performed until 4 hours after the associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 21.7% RTP. 3. Criterion c is only applicable when pump speed is ≤ 60% rated speed. ---------- Verify at least one of the following criteria (a, b or c, as applicable) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns. c. The recirculation pump flow to speed ratio, jet pump loop flow to recirculation pump speed ratio, and jet pump diffuser to lower plenum differential pressure ratios are evaluated as being acceptable.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety Relief Valves (SRVs) and Safety Valves (SVs)

LCO 3.4.3 The safety function of 8 SRVs and SVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SRV or SV inoperable.	A.1 Restore the valve to OPERABLE status.	30 days
B. Two SRVs or SVs inoperable.	B.1 Restore one valve to OPERABLE status.	7 days
C. Required Action and associated Completion Time of Condition A or B not met. OR Three or more SRVs or SVs inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the SRVs and SVs are as follows: Number of SRVs / Setpoint (psig) 1 / 1110 ± 33.0 1 / 1120 ± 33.0 2 / 1130 ± 33.0 2 / 1140 ± 33.0 Number of SVs / Setpoint (psig) 2 / 1240 ± 36.0 Following testing, lift settings shall be within ± 1%.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.4.3.2	Verify each SRV actuator strokes when manually actuated.	In accordance with the INSERVICE TESTING PROGRAM

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Operational LEAKAGE

LCO 3.4.4 RCS operational LEAKAGE shall be limited to:

a. ≤ 5 gpm unidentified LEAKAGE;

b. ≤ 25 gpm total LEAKAGE averaged over the previous 24 hour period; and

c. ≤ 2 gpm increase in unidentified LEAKAGE within the previous 24 hour period in MODE 1.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Unidentified LEAKAGE not within limit. OR Total LEAKAGE not within limit.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Unidentified LEAKAGE increase not within limit.	B.1 Reduce unidentified LEAKAGE increase to within limits. OR	4 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Verify source of unidentified LEAKAGE increase is not service sensitive type 304 or type 316 austenitic stainless steel.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Leakage Detection Instrumentation

LCO 3.4.5 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One channel of the Drywell Sump System; and

b. One channel of the Primary Containment Air Sampling System.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required Drywell Sump System inoperable.	A.1 Restore required Drywell Sump System to OPERABLE status.	24 hours
B. Required Primary Containment Air Sampling System inoperable.	B.1 Initiate action to restore required Primary Containment Air Sampling System to OPERABLE status.	Immediately
C. Required Drywell Sump System inoperable. AND Required Primary Containment Air Sampling System inoperable.	C.1 Restore required Drywell Sump System to OPERABLE status. OR C.2 Restore required Primary Containment Air Sampling System to OPERABLE status.	4 hours 4 hours
D. Required Action and associated Completion Time of Condition A or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Perform a CHANNEL CHECK of required Primary Containment Air Sampling System.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.2	Perform a CHANNEL FUNCTIONAL TEST of required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator, and floor drain sump flow integrator.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.3	Perform a CHANNEL FUNCTIONAL TEST of required equipment drain sump flow timer and floor drain sump flow timer.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.4	Perform a CHANNEL CALIBRATION of required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator, and floor drain sump flow integrator.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.5	Perform a CHANNEL CALIBRATION of required equipment drain sump flow timer and floor drain sump flow timer.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Specific Activity

LCO 3.4.6 The specific activity of the reactor coolant shall be limited to DOSE EQUIVALENT I-131 specific activity $\leq$ 0.2 μCi/gm.

APPLICABILITY: MODE 1,
MODES 2 and 3 with any main steam line not isolated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor coolant specific activity $>$ 0.2 μCi/gm and $\leq$ 2.0 μCi/gm DOSE EQUIVALENT I-131.	----------NOTE---------- LCO 3.0.4.c is applicable. ---------- A.1 Determine DOSE EQUIVALENT I-131. AND A.2 Restore DOSE EQUIVALENT I-131 to within limits.	 Once per 4 hours 48 hours
B. Required Action and associated Completion Time of Condition A not met. OR Reactor Coolant specific activity $>$ 2.0 μCi/gm DOSE EQUIVALENT I-131.	B.1 Determine DOSE EQUIVALENT I-131. AND B.2.1 Isolate all main steam lines. OR B.2.2.1 Be in MODE 3. AND B.2.2.2 Be in MODE 4.	Once per 4 hours 12 hours 12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is $\leq$ 0.2 μCi/gm.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System — Hot Shutdown

LCO 3.4.7 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

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

1. Both required RHR shutdown cooling subsystems and recirculation pumps may not be in operation for up to 2 hours per 8 hour period.

2. One required RHR shutdown cooling subsystem may be inoperable for up to 2 hours for the performance of Surveillances.

APPLICABILITY: MODE 3, with reactor steam dome pressure < the RCIC Steam Supply Line Pressure – Low isolation pressure.

ACTIONS

----------NOTE----------

Separate Condition entry is allowed for each RHR shutdown cooling subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required RHR shutdown cooling subsystems inoperable.	A.1 Initiate action to restore required RHR shutdown cooling subsystem(s) to OPERABLE status. AND	Immediately (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Verify by administrative means an alternate method of decay heat removal is available for each required inoperable RHR shutdown cooling subsystem.	1 hour
	AND		
	A.3	Be in MODE 4.	24 hours
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1	Initiate action to restore one RHR shutdown cooling subsystem or one recirculation pump to operation.	Immediately
	AND		
	B.2	Verify reactor coolant circulation by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND		
	B.3	Monitor reactor coolant temperature and pressure.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	----------NOTE---------- Not required to be met until 2 hours after reactor steam dome pressure is < the RCIC Steam Supply Line Pressure – Low isolation pressure. ---------- Verify one required RHR shutdown cooling subsystem or recirculation pump is operating.	In accordance with the Surveillance Frequency Control Program
SR 3.4.7.2	----------NOTE---------- Not required to be performed until 12 hours after reactor steam dome pressure is < the RCIC Steam Supply Line Pressure – Low isolation pressure. ---------- Verify RHR shutdown cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 Residual Heat Removal (RHR) Shutdown Cooling System — Cold Shutdown

LCO 3.4.8 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

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

1. Both required RHR shutdown cooling subsystems and recirculation pumps may not be in operation for up to 2 hours per 8 hour period.

2. One required RHR shutdown cooling subsystem may be inoperable for up to 2 hours for the performance of Surveillances.

APPLICABILITY: MODE 4.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each shutdown cooling subsystem.

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or two required RHR shutdown cooling subsystems inoperable.	A.1	Verify by administrative means an alternate method of decay heat removal is available for each inoperable required RHR shutdown cooling subsystem.	1 hour AND Once per 24 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1 Verify reactor coolant circulation by an alternate method. AND B.2 Monitor reactor coolant temperature.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one required RHR shutdown cooling subsystem or one recirculation pump is operating.	In accordance with the Surveillance Frequency Control Program
SR 3.4.8.2	Verify RHR shutdown cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.9 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation pump starting temperature requirements shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Required Action A.2 shall be completed if this Condition is entered. ---------- Requirements of the LCO not met in MODE 1, 2, or 3.	A.1 Restore parameter(s) to within limits. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. ----------NOTE---------- Required Action C.2 shall be completed if this Condition is entered. ---------- Requirements of the LCO not met in other than MODES 1, 2, and 3.	C.1 Initiate action to restore parameter(s) to within limits. AND C.2 Determine RCS is acceptable for operation.	Immediately Prior to entering MODE 2 or 3.

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.9.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ---------- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.9.2	Verify RCS pressure and RCS temperature are within the criticality limits specified in the PTLR.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.9.3	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup. ---------- Verify the difference between the bottom head coolant temperature and the Reactor Pressure Vessel (RPV) coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.9.4	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup. ---------- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.9.5	----------NOTE---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ----------	
	Verify temperatures at the reactor vessel head flange and the shell adjacent to the head flange are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.9.6	----------NOTE---------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. ----------	
	Verify temperatures at the reactor vessel head flange and the shell adjacent to the head flange are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program
SR 3.4.9.7	----------NOTE---------- Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4. ----------	
	Verify temperatures at the reactor vessel head flange and the shell adjacent to the head flange are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1025 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify reactor steam dome pressure is ≤ 1025 psig.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS — Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of four safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except High Pressure Coolant Injection (HPCI) is not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 100 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Residual Heat Removal (RHR) pump inoperable.	A.1 Restore RHR pump to OPERABLE status.	30 Days
B. One low pressure ECCS subsystem inoperable for reasons other than Condition A.	B.1 Restore low pressure ECCS subsystem to OPERABLE status.	7 days
C. One Core Spray subsystem inoperable. AND One or two RHR pump(s) inoperable.	C.1 Restore Core Spray subsystem to OPERABLE status. OR C.2 Restore RHR pump(s) to OPERABLE status.	72 hours 72 hours
D. Both Core Spray subsystems inoperable.	D.1 Restore one Core Spray subsystem to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. HPCI System inoperable.	F.1 Verify by administrative means RCIC System is OPERABLE. AND F.2 Restore HPCI System to OPERABLE status.	Immediately 14 days
G. HPCI System inoperable. AND One RHR pump inoperable.	G.1 Restore HPCI System to OPERABLE status. OR G.2 Restore RHR pump to OPERABLE status.	7 days 7 days
H. HPCI System inoperable. AND One low pressure ECCS subsystem is inoperable for reasons other than Condition A.	H.1 Restore HPCI System to OPERABLE status. OR H.2 Restore low pressure ECCS subsystem to OPERABLE status.	72 hours 72 hours
I. HPCI System inoperable. AND One ADS valve inoperable.	I.1 Restore HPCI System to OPERABLE status. OR I.2 Restore ADS valve to OPERABLE status.	72 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. Required Action and associated Completion Time of Condition F, G, H, or I not met.	J.1 Be in MODE 3. AND J.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
K. One ADS valve inoperable.	K.1 Restore ADS valve to OPERABLE status.	30 days
L. One ADS valve inoperable. AND One low pressure ECCS subsystem inoperable for reasons other than Condition A.	L.1 Restore ADS valve to OPERABLE status. OR L.2 Restore low pressure ECCS subsystem to OPERABLE status.	72 hours 72 hours
M. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition K or L not met.	M.1 Be in MODE 3. AND M.2 Reduce reactor steam dome pressure to ≤ 100 psig.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
N. Two or more low pressure ECCS subsystems inoperable for reasons other than Condition C or D. OR HPCI System and two or more ADS valves inoperable. OR HPCI System and two or more low pressure ECCS subsystems inoperable. OR One ADS valve and two or more low pressure ECCS subsystems inoperable. OR One ADS valve and HPCI System and one low pressure ECCS subsystem inoperable.	N.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.2	----------NOTE---------- The low pressure coolant injection (LPCI) system may be considered OPERABLE during alignment and operation for decay heat removal in MODE 3, if capable of being manually realigned and not otherwise inoperable. ---------- ----------NOTE---------- Not required to be met for system vent flow paths opened under administrative control. ---------- Verify each ECCS injection/spray subsystem power operated and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.3	Verify a 30 day supply of nitrogen exists for each ADS accumulator.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.4	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray: ≥ 2718 gpm / 1 / ≥ 113 psig LPCI: ≥ 4320 gpm / 1 / ≥ 20 psig	In accordance with the INSERVICE TESTING PROGRAM

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.5	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 1025 and ≥ 940 psig, the HPCI pump can develop a flow rate ≥ 2700 gpm against a system head corresponding to reactor pressure.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.5.1.6	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 160 psig, the HPCI pump can develop a flow rate ≥ 2700 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.7	----------NOTES---------- 1. Vessel injection /spray may be excluded. 2. For the LPCI System, the Surveillance may be met by any series of sequential and/or overlapping steps, such that the LPCI Loop Select function is tested. ---------- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.8	----------NOTE---------- Valve actuation may be excluded. ---------- Verify the ADS actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.9	Verify each ADS valve actuator strokes when manually actuated.	In accordance with the INSERVICE TESTING PROGRAM

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control

LCO 3.5.2 DRAIN TIME of RPV water inventory to the TS 2.1.1.3 Safety Limit shall be ≥ 36 hours.

AND

One low pressure ECCS subsystem shall be OPERABLE.

APPLICABILITY: MODES 4 and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS subsystem inoperable.	A.1 Restore required ECCS subsystem to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to establish a method of water injection capable of operating without offsite electrical power.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. DRAIN TIME < 36 hours and ≥ 8 hours.	C.1 Verify secondary containment boundary is capable of being established in less than the DRAIN TIME. AND C.2 Verify each secondary containment penetration flow path is capable of being isolated in less than the DRAIN TIME. AND C.3 Verify one standby gas treatment subsystem is capable of being placed in operation in less that the DRAIN TIME.	4 hours 4 hours 4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. DRAIN TIME < 8 hours.	D.1 ---------- NOTE ---------- Required ECCS injection/spray subsystem or additional method of water injection shall be capable of operating without offsite electrical power. ---------- Initiate action to establish an additional method of water injection with water sources capable of maintaining RPV water level > TS 2.1.1.3 Safety Limit for ≥ 36 hours.	Immediately
	AND	
	D.2 Initiate action to establish secondary containment boundary.	Immediately
	AND	
	D.3 Initiate action to isolate each secondary containment penetration flow path or verify it can be manually isolated from the control room.	Immediately
	AND	
	D.4 Initiate action to verify one standby gas treatment subsystem is capable of being placed in operation.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition C or D not met. OR DRAIN TIME < 1 hour.	E.1 Initiate action to restore DRAIN TIME to ≥ 36 hours.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify DRAIN TIME ≥ 36 hours.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.2	Verify, for a required Low Pressure Coolant Injection (LPCI) subsystem, the suppression pool water level is ≥ 7.0 ft.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	Verify, for a required Core Spray (CS) subsystem, the: a. Suppression pool water level is ≥ 8.0 ft; or b. Condensate storage tank water level in one CST is ≥ 11 ft or ≥ 7 ft in both CSTs.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.4	Verify, for the required ECCS injection/spray subsystem, locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.5	----------NOTE---------- A LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. ---------- ----------NOTE---------- Not required to be met for system vent flow paths opened under administrative control. ---------- Verify, for the required ECCS subsystem, each power operated and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.6	Operate the required ECCS subsystem through the recirculation line for ≥ 10 minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.7	Verify each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated isolation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.8	----------NOTE---------- Vessel injection/spray may be excluded. ---------- Verify the required ECCS injection/spray subsystem can be manually operated.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Coolant Injection System is OPERABLE. AND A.2 Restore RCIC System to OPERABLE status.	Immediately 14 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.5.3.1	Verify the RCIC System locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.2	----------NOTE----------Not required to be met for system vent flow paths opened under administrative control. ----------	
	Verify each RCIC System power operated and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.3	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ----------	
	Verify, with reactor pressure $\leq$ 1025 psig and $\geq$ 940 psig, the RCIC pump can develop a flow rate $\geq$ 400 gpm against a system head corresponding to reactor pressure.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.5.3.4	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ----------	
	Verify, with reactor pressure $\leq$ 160 psig, the RCIC pump can develop a flow rate $\geq$ 400 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.3.5	----------NOTE---------- Vessel injection may be excluded. ---------- Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.1 Primary Containment

LCO 3.6.1.1 Primary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Primary containment inoperable.	A.1 Restore primary containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with the Primary Containment Leakage Rate Program.	In accordance with the Primary Containment Leakage Rate Program.
SR 3.6.1.1.2	Verify suppression chamber pressure does not increase at a rate $>$ 0.009 psi per minute tested over a 10 minute period at a differential pressure of $>$ 1.0 psid.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.2 Primary Containment Air Lock

LCO 3.6.1.2 The primary containment air lock shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

1. Entry and exit is permissible to perform repairs of the air lock components.

2. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, “Primary Containment,” when air lock leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One primary containment air lock door inoperable.	----------NOTES---------- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls. ---------- A.1 Verify the OPERABLE door is closed. AND	1 hour (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 Lock the OPERABLE door closed. AND A.3 ----------NOTE---------- Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. ----------	24 hours Once per 31 days
	Verify the OPERABLE door is locked closed.	
B. Primary containment air lock interlock mechanism inoperable.	----------NOTES---------- 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the air lock are inoperable and Condition C is entered. 2. Entry into and exit from containment is permissible under the control of a dedicated individual. ---------- B.1 Verify an OPERABLE door is closed. AND	 1 hour (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Lock an OPERABLE door closed. AND	24 hours
	B.3 ----------NOTE---------- Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. ---------- Verify an OPERABLE door is locked closed.	Once per 31 days
C. Primary containment air lock inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results. AND	Immediately
	C.2 Verify a door is closed. AND	1 hour
	C.3 Restore air lock to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria Applicable to SR 3.6.1.1.1. ---------- Perform required primary containment air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program. The acceptance criterion for air lock testing is overall air lock leakage rate $\leq 0.05\ L_a$ when tested at $\geq P_a$.	In accordance with the Primary Containment Leakage Rate Testing Program.
SR 3.6.1.2.2	Verify only one door in the primary containment air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, “Primary Containment,” when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria in MODES 1, 2, and 3.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with one PCIV inoperable except for MSIV or purge valve leakage not within limits.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND	4 hours except for main steam line AND 8 hours for main steam line

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with two PCIVs inoperable except for MSIV or purge valve leakage not within limits.	B.1 Isolate the affected penetration flow path by use of at least one closed and de–activated automatic valve, closed manual valve, or blind flange.	1 hour
C. ----------NOTE---------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND C.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	72 hours Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more penetration flow paths with one or more MSIVs not within leakage limits.	D.1 Restore leakage to within limits.	8 hours
E. One or more penetration flow paths with one or more containment purge valves not within purge valve leakage limits.	E.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND E.2 ----------NOTE---------- Only required to be performed if a purge valve with resilient seal is used to satisfy Required Action E.1. ---------- Restore leakage to within limits. AND E.3 ---------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	24 hours 72 hours Once per 31 days for isolation device outside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	----------NOTE---------- Not required to be met when the 18 inch primary containment purge valves are open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. ---------- Verify each 18 inch primary containment purge valve is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.2	Verify continuity of the traversing incore probe (TIP) shear isolation valve explosive charge.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.3	Verify the isolation time of each power operated automatic PCIV, except for MSIVs, is within limits.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.1.3.4	Perform leakage rate testing for each primary containment purge valve with resilient seals.	In accordance with the Surveillance Frequency Control Program AND Once within 92 days after opening the valve

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.5	Verify the isolation time of each MSIV is > 3 seconds and < 5 seconds.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.1.3.6	----------NOTE---------- For the MSIVs, this SR may be met by any series of sequential, overlapping, or total system steps, such that proper operation is verified. ---------- Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.7	Verify a representative sample of reactor instrumentation line EFCVs actuate on a simulated instrument line break to restrict flow.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.8	Remove and test the explosive squib from each shear isolation valve of the TIP System.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.1.3.9	Verify leakage rate through each MSIV is ≤ 100 scfh and that the combined maximum pathway leakage rate for all four main steam lines is ≤ 200 scfh when tested at ≥ 24 psig.	In accordance with the Primary Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Air Temperature

LCO 3.6.1.4 Drywell average air temperature shall be ≤ 135°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1 Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.4.1	Verify drywell average air temperature is within limit.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Low-Low Set (LLS) Valves

LCO 3.6.1.5 The LLS function of two safety/relief valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LLS valve inoperable.	A.1 Restore LLS valve to OPERABLE status.	14 days
B. Required Action and associated Completion Time of Condition A not met. OR Two LLS valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.5.1	Verify each LLS valve actuator strokes when manually actuated.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.1.5.2	----------NOTE---------- Valve actuation may be excluded. ---------- Verify the LLS System actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

LCO 3.6.1.6 Each reactor building-to suppression chamber vacuum breaker assembly shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each reactor building-to-suppression chamber vacuum breaker assembly.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two reactor building-to-suppression chamber vacuum breaker assemblies with one valve not closed.	A.1 Close the open vacuum breaker assembly valve.	72 hours
B. One or two reactor building-to-suppression chamber vacuum breaker assemblies with both valves not closed.	B.1 Close one open vacuum breaker assembly valve.	1 hour
C. One reactor building-to-suppression chamber vacuum breaker assembly with one or two valves inoperable for opening.	C.1 Restore the vacuum breaker assembly to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two reactor building-to-suppression chamber vacuum breaker assemblies with one or two valves inoperable for opening.	D.1 Restore both valves in one vacuum breaker assembly to OPERABLE status.	1 hour
E. Required Action and Associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	----------NOTES---------- 1. Not required to be met for vacuum breaker assembly valves that are open during Surveillances. 2. Not required to be met for vacuum breaker assembly valves open when performing their intended function. ---------- Verify each vacuum breaker assembly valve is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.6.2	Perform a functional test of each vacuum breaker assembly valve.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.3	Verify the opening setpoint of each vacuum breaker assembly valve is $\leq$ 0.614 psid.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.7 Six suppression chamber-to-drywell vacuum breakers shall be OPERABLE for opening.

AND

Seven suppression chamber-to-drywell vacuum breakers shall be closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore one vacuum breaker to OPERABLE status.	72 hours
B. One suppression chamber-to-drywell vacuum breaker not closed.	B.1 Close the open vacuum breaker.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.1.7.1	----------NOTE---------- Not required to be met for vacuum breakers that are open during Surveillances. ---------- Verify each vacuum breaker is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.7.2	Perform a functional test of each required vacuum breaker.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.7.3	Verify the opening setting of each required vacuum breaker is $\leq$ 0.5 psid.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.2.1 Suppression Pool Average Temperature

LCO 3.6.2.1 Suppression pool average temperature shall be:

a. ≤ 95°F when any OPERABLE intermediate range monitor (IRM) is > 25/40 divisions of full scale on Range 7 and no testing that adds heat to the suppression pool is being performed;

b. ≤ 105°F when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7 and testing that adds heat to the suppression pool is being performed; and

c. ≤ 110°F when all OPERABLE IRM channels are ≤ 25/40 divisions of full scale on Range 7.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool average temperature > 95°F but ≤ 110°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Not performing testing that adds heat to the suppression pool.	A.1 Verify suppression pool average temperature ≤ 110°F. AND A.2 Restore suppression pool average temperature to ≤ 95°F.	Once per hour 24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER until all OPERABLE IRM channels ≤ 25/40 divisions of full scale on Range 7.	12 hours
C. Suppression pool average temperature > 105°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F but ≤ 120°F.	D.1 Place the reactor mode switch in the Shutdown position. AND D.2 Verify suppression pool average temperature ≤ 120°F. AND D.3 Be in MODE 4.	Immediately Once per 30 minutes 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Suppression pool average temperature > 120°F.	E.1 Depressurize the reactor vessel to < 200 psig. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	In accordance with the Surveillance Frequency Control Program AND 5 minutes when performing testing that adds heat to the suppression pool

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 10.11 ft and ≤ 10.43 ft.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool water level not within limits.	A.1 Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR pump inoperable.	A.1 Restore RHR pump to OPERABLE status.	30 days
B. One RHR pump in each suppression pool cooling subsystem inoperable.	B.1 Restore one RHR pump to OPERABLE status.	7 days
C. One RHR suppression pool cooling subsystem inoperable for reasons other than Condition A.	C.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days
D. Two RHR suppression pool cooling subsystems inoperable for reasons other than Condition B.	D.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify by administrative means each RHR suppression pool cooling subsystem manual, power operated and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.6.2.3.2	Verify each RHR pump develops a flow rate $\geq$ 4800 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.2.3.3	Verify RHR suppression pool cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

LCO 3.6.2.4 Two RHR suppression pool spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	30 days
B. Two RHR suppression pool spray subsystems inoperable.	B.1 Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify by an air test that the suppression pool spray header and nozzles are unobstructed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.2.4.2	Verify RHR suppression pool spray subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

Previous TS 3.6.3.1 Containment Atmosphere Dilution (CAD) System was deleted in Amendment 265

This page is a placeholder for this TS number. It is not reassigned to another TS requirement.

3.6 CONTAINMENT SYSTEMS

3.6.3.2 Primary Containment Oxygen Concentration

LCO 3.6.3.2 The primary containment oxygen concentration shall be < 4.0 volume percent.

APPLICABILITY: MODE 1 during the time period:

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to reactor shutdown.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Primary containment oxygen concentration not within limit.	A.1 Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.2.1	Verify primary containment oxygen concentration is within limits.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4.1 Secondary Containment

LCO 3.6.4.1 The secondary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Secondary containment inoperable.	A.1 Restore secondary containment to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify all secondary containment equipment hatches are closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	----------NOTE---------- Doors in high radiation areas may be verified by administrative means. ----------	
	Verify that either the outer door(s) or the inner door(s) in each secondary containment access opening are closed, except when the access opening is being used for entry and exit.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	Verify each SBGT subsystem can maintain $\geq$ 0.25 inch of vacuum water gauge in the secondary containment at a flow rate $\leq$ 4000 cfm.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves/Dampers (SCIV/Ds)

LCO 3.6.4.2 Each SCIV/D shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIV/Ds.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV/D inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve/damper, closed manual valve, or blind flange. AND	8 hours (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	 Once per 31 days
B. ----------NOTE---------- Only applicable to penetration flow paths with two isolation valves/dampers. ---------- One or more penetration flow paths with two SCIV/Ds inoperable.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve/damper, closed manual valve, or blind flange.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	Verify the isolation time of each power operated automatic SCIV/D is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.2.2	Verify each automatic SCIV/D actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SBGT) System

LCO 3.6.4.3 Two SBGT subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SBGT subsystem inoperable.	A.1 Restore SBGT subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. Two SBGT subsystems inoperable.	C.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.3.1	Operate each SBGT subsystem for ≥ 15 continuous minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.3.2	----------NOTE---------- When a SBGT subsystem is placed in an inoperable status solely for the performance of VFTP testing required by this Surveillance on the other subsystem, entry into associated Conditions and Required Actions may be delayed for up to 1 hour. ---------- Perform required SBGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SBGT subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.3.4	Verify each SBGT filter cooler bypass damper can be opened and the fan started.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHRSW pump inoperable.	A.1 Restore RHRSW pump to OPERABLE status.	30 days
B. One RHRSW pump in each subsystem inoperable.	B.1 Restore one RHRSW pump to OPERABLE status.	7 days
C. One RHRSW subsystem inoperable for reasons other than Condition A.	C.1 ----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, “Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown,” for RHR shutdown cooling made inoperable by RHRSW System. ---------- Restore RHRSW subsystem to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Both RHRSW subsystems inoperable for reasons other than Condition B.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by RHRSW System. ---------- D.1 Restore one RHRSW subsystem to OPERABLE status.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each RHRSW subsystem power operated and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.2 River Water Supply (RWS) System and Ultimate Heat Sink (UHS)

LCO 3.7.2 Two RWS subsystems and UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RWS subsystem inoperable.	A.1 Restore the RWS subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Both RWS subsystems inoperable. <u>OR</u> UHS inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, “Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown,” for RHR shutdown cooling made inoperable by RWS System. ---------- B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	 12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify the river water level is ≥ 725.2 ft mean sea level.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.2	Verify the average river water temperature is ≤ 95°F.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.3	----------NOTE---------- Not required to be performed until river depth < 2 feet at the intake structure. ---------- Verify the river water depth is ≥ 12 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.4	Verify each RWS subsystem power operated and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.5	Verify the river water depth ≥ 12 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.6	Verify each RWS subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.3 Emergency Service Water (ESW) System

LCO 3.7.3 Two ESW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ESW subsystem inoperable.	----------NOTES---------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, “AC Sources-Operating,” for diesel generator made inoperable by ESW System. 2. Enter applicable Conditions and Required Actions of LCO 3.4.7, “Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown,” for RHR shutdown cooling made inoperable by ESW System. ---------- A.1 Restore the ESW subsystem to OPERABLE status.	7 days
B. Required Action and Associated Completion Time of Condition A not met. OR Both ESW subsystems inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	----------NOTE---------- Isolation of flow to individual components does not render ESW System inoperable. ---------- Verify each ESW subsystem power operated and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.3.2	Verify each ESW subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.4 Standby Filter Unit (SFU) System

LCO 3.7.4 Two SFU subsystems shall be OPERABLE.

----------NOTE----------
The control building envelope (CBE) boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SFU subsystem inoperable for reasons other than Condition B.	A.1 Restore SFU subsystem to OPERABLE status.	7 days
B. One or more SFU subsystems inoperable due to inoperable CBE boundary in MODES 1, 2, and 3.	B.1 Initiate actions to implement mitigating actions. AND B.2 Verify mitigating actions ensure CBE occupant exposures to radiological hazards will not exceed limits and verify by administrative means that CBE occupants are protected from smoke and chemical hazards. AND B.3 Restore CBE boundary to OPERABLE status.	Immediately 24 hours 90 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Required Action and associated Completion Time of Condition A not met during movement of irradiated fuel assemblies in the secondary containment during CORE ALTERATIONS.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- D.1 Place OPERABLE SFU subsystem in the isolation mode. OR D.2.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND D.2.2 Suspend CORE ALTERATIONS.	 Immediately Immediately Immediately
E. Both SFU subsystems inoperable in MODE 1, 2 or 3 for reasons other than Condition B.	E.1 Enter LCO 3.0.3	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Both SFU subsystems inoperable during movement of irradiated fuel assembles in the secondary containment during CORE ALTERATIONS. OR One or more SFU subsystems inoperable due to an inoperable CBE boundary during movement of irradiated fuel assemblies in the secondary containment during CORE ALTERATIONS.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- F.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND F.2 Suspend CORE ALTERATIONS.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Operate each SFU subsystem for ≥ 15 minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.7.4.2	Perform required SFU filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.4.3	Verify each SFU subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.4.4	Perform required CBE unfiltered air inleakage testing in accordance with the Control Building Envelope Habitability Program.	In accordance with the Control Building Envelope Habitability Program

3.7 PLANT SYSTEMS

3.7.5 Control Building Chiller (CBC) System

LCO 3.7.5 Two CBC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CBC subsystem inoperable.	A.1 Restore CBC subsystem to OPERABLE status.	30 days
B. Two CBC subsystems inoperable.	B.1 Verify control building area temperatures < 90°F. AND B.2 Restore one CBC subsystem to OPERABLE status.	Once per 4 hours 72 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A not met during movement of irradiated fuel assemblies in the secondary containment during CORE ALTERATIONS.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- D.1 Place OPERABLE CBC subsystem in operation. OR D.2.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND D.2.2 Suspend CORE ALTERATIONS.	Immediately Immediately Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition B not met during movement of irradiated fuel assemblies in the secondary containment during CORE ALTERATIONS.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- E.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND E.2 Suspend CORE ALTERATIONS.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify each CBC subsystem has the capability to remove the available heat load.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.6 Main Condenser Offgas

LCO 3.7.6 The gross gamma activity rate of the noble gases measured at the Steam Jet Air Ejector (SJAE) offgas pretreatment monitor shall be $\leq$ 1.0 Ci/second after decay of 30 minutes.

APPLICABILITY: MODE 1,
MODES 2 and 3 with any main steam line not isolated and SJAE in operation.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Gross gamma activity rate of the noble gases not within limit.	A.1 Restore gross gamma activity rate of the noble gases to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Isolate all main steam lines.	12 hours
	OR	
	B.2 Isolate SJAE.	12 hours
	OR	
	B.3.1 Be in MODE 3.	12 hours
	AND	
	B.3.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	----------NOTE---------- Not required to be performed until 31 days after any main steam line not isolated and SJAE in operation. ----------	
	Verify the gross gamma activity rate of the noble gases is $\leq$ 1.0 Ci/second after decay of 30 minutes.	In accordance with the Surveillance Frequency Control Program AND Once within 4 hours after a $\geq$ 50% increase in the nominal steady state fission gas release after factoring out increases due to changes in THERMAL POWER level

3.7 PLANT SYSTEMS

3.7.7 The Main Turbine Bypass System

LCO 3.7.7 The Main Turbine Bypass System shall be OPERABLE.

OR

LCO 3.2.2, “MINIMUM CRITICAL POWER RATIO (MCPR),” limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are made applicable.

APPLICABILITY: THERMAL POWER ≥ 21.7% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.7% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify one complete cycle of each main turbine bypass valve.	In accordance with the Surveillance Frequency Control Program
SR 3.7.7.2	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program
SR 3.7.7.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.8 Spent Fuel Storage Pool Water Level

LCO 3.7.8 The spent fuel storage pool water level shall be ≥ 36 ft.

APPLICABILITY: During movement of irradiated fuel assemblies in the spent fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent fuel storage pool water level not within limit.	A.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the spent fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	Verify the spent fuel storage pool water level is ≥ 36 ft.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.9 Control Building/Standby Gas Treatment (CB/SBGT) Instrument Air System

LCO 3.7.9 Two CB/SBGT Instrument Air subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CB/SBGT Instrument Air subsystem inoperable.	A.1 Declare required feature(s), supported by the inoperable CB/SBGT Instrument Air subsystem, inoperable when the redundant required feature(s) are inoperable. AND A.2 Restore the CB/SBGT Instrument Air subsystem to OPERABLE status.	4 hours from discovery of Condition A concurrent with inoperability of redundant required feature(s) 7 days
B. Required Action and Associated Completion Time of Condition A not met. OR Both CB/SBGT Instrument Air subsystems inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Operates each CB/SBGT Instrument Air compressor for ≥ 20 minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.2	Verify each CB/SBGT Instrument Air subsystem actuates on an actual or simulated initiation signal and maintains air pressure ≥ 75 psig in the receiver.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources — Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Two diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit. AND	1 hour AND Once per 24 hours thereafter
	A.2 Restore offsite circuit to OPERABLE status.	Prior to entering MODE 2 from MODE 3 or 4

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit(s). AND	1 hour AND Once per 12 hours thereafter
	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable. AND	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.3 Determine OPERABLE DG is not inoperable due to common cause failure. AND ----------NOTE---------- Not required to be performed when the cause of the inoperable DG is pre-planned, preventive maintenance and testing. ---------- B.4 Perform SR 3.8.1.2 for OPERABLE DG. AND B.5 Restore DG to OPERABLE status.	24 hours Once per 72 hours 7 days AND 8 days from discovery of failure to meet LCO expect for Condition A
C. Two offsite circuits inoperable.	C.1 Declare required feature(s) inoperable when the redundant required feature(s) are inoperable. AND	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Restore one offsite circuit to OPERABLE status.	24 hours AND 8 days from discovery of failure to meet LCO except for Condition A
D. Two DGs inoperable.	D.1 Restore one DG to OPERABLE status.	2 hours
E. Required Action and Associated Completion Time of Condition A, B, C, or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. Three or more AC sources inoperable.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 2. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. 3. When a DG is placed in an inoperable status solely for the performance of testing required by Required Actions B.3 or B.4, entry into associated Conditions and Required Actions may be delayed for up to 2 hours. ---------- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 3744v and ≤ 4576v and frequency ≥ 59.5Hz and ≤ 60.5Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. ---------- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 2750kw and ≤ 2950kw.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.4	Verify each tank contains ≥ 220 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for the presence of water in the fuel oil in each day tank and remove water as necessary.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify the fuel oil transfer system operates to transfer fuel oil from storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ----------	
	Verify each DG starts from standby condition and achieves: a. in ≤ 10 seconds, voltage ≥ 3744V and frequency ≥ 59.5Hz; and b. steady state, voltage ≥ 3744V and ≤ 4576V and frequency ≥ 59.5Hz and ≤ 60.5Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	----------NOTE---------- The Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify automatic slow transfer of AC power supply from the Startup Transformer to the Standby Transformer.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTE----------This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 64.5Hz. b. Within 1.3 seconds following load rejection, the voltage is ≥ 3744V and ≤ 4576V. c. Within 3.9 seconds following load rejection, the frequency is ≥ 59.5Hz and ≤ 60.5Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG's automatic trips are bypassed on an actual or simulated Loss of Offsite Power (LOOP) signal or on an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator lockout.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.11 ----------NOTE----------This Surveillance shall not be performed in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify under manual control each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.12 ----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load block is ≥ 2 seconds.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.13 ----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of essential buses; b. Load shedding from essential buses; and c. DG auto-start from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads in the proper timed sequence, 3. achieves steady state voltage ≥ 3744V and ≤ 4576V, 4. achieves steady state frequency ≥ 59.5Hz and ≤ 60.5Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources — Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8, “Distribution Systems — Shutdown”; and

b. One Diesel Generator (DG) capable of supplying one division of the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

----------NOTE----------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	----------NOTE---------- Enter applicable Condition and Required Actions of LCO 3.8.8, with one required division de-energized as a result of Condition A. --- A.1 Declare affected required feature(s), with no offsite power available, inoperable. OR A.2.1 Suspend CORE ALTERATIONS. AND A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment. AND A.2.3 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately Immediately Immediately Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required DG inoperable.	B.1 Suspend CORE ALTERATIONS. AND B.2 Suspend movement of irradiated fuel assemblies in secondary containment AND B.3 Initiate action to restore required DG to OPERABLE status.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	----------NOTES---------- 1. The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.13. 2. SR 3.8.1.13 is considered to be met without the ECCS initiation signals OPERABLE when the ECCS initiation signals are not required to be OPERABLE per Table 3.3.5.1-1. ---------- For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, except SR 3.8.1.8, are applicable.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required Diesel Generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

----------NOTE----------
For Conditions B, E, and F separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel oil level less than a 7 day supply and greater than a 6 day supply.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory less than a 7 day supply and greater than a 6 day supply.	B.1 Restore lube oil inventory to within limits.	48 hours
C. Stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates to within limits.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. New fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. One or more DGs with required starting air receiver pressures < 150 psig and ≥ 75 psig.	E.1 Restore required starting air receiver pressure to within limits.	48 hours
F. Required Action and associated Completion Time not met. OR One or more DGs with diesel fuel oil, lube oil, or starting air subsystems not within limits for reasons other than Condition A, B, C, D, or E.	F.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify fuel oil storage tank contains a ≥ 7 day supply of fuel.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.2	Verify lube oil inventory is a ≥ 7 day supply for each DG.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify required air start receiver pressure is ≥ 150 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.5	Check for the presence of water in the fuel oil in the fuel oil storage tank and remove water as necessary.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources — Operating

LCO 3.8.4 Both Division 1 and Division 2 125 VDC electrical power subsystems and the 250 VDC electrical power subsystem shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One 125 VDC electrical power subsystem inoperable.	A.1	Restore 125 VDC electrical power subsystem to OPERABLE status.	8 hours
OR	NOTE: May be used on a one-time-only basis for each battery division.	A.2.1	Declare required feature(s), supported by the inoperable 125 VDC source, inoperable when the redundant required feature(s) are inoperable. AND	4 hours from discovery of Condition A concurrent with inoperability of redundant required feature(s).
		A.2.2	Restore 125 VDC electrical power subsystem to OPERABLE status.	10 days
B.	Required Action and Associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	12 hours
		AND		
		B.2.	Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. 250 VDC electrical power subsystem inoperable.	C.1 Declare associated supported features inoperable.	Immediately
D. Two or more DC electrical power subsystems inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ 130.5 V on float charge for the 125 VDC battery and ≥ 252 V for the 250 VDC battery.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.4	Remove visible corrosion and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.5	Verify battery connection resistance within limits.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.6	----------NOTE---------- This Surveillance shall not be performed on the required battery chargers in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each required battery charger supplies ≥ 293 amps at ≥ 132.5 V for the 125 VDC subsystem and ≥ 200 amps at ≥ 258 V for the 250 VDC subsystem.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.7	----------NOTES---------- 1. The modified performance discharge test in SR 3.8.4.8 may be performed in lieu of the service test in SR 3.8.4.7. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify 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.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	In accordance with the Surveillance Frequency Control Program AND 12 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources — Shutdown

LCO 3.8.5 DC electrical power subsystems shall be OPERABLE to support the DC electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems — Shutdown."

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

----------NOTE----------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable. OR A.2.1 Suspend CORE ALTERATIONS. AND A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment. AND	Immediately Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.3 Initiate action to restore required DC electrical power susbsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	----------NOTE---------- The following SRs are not required to be performed: SR 3.8.4.7 and SR 3.8.4.8. --- For DC electrical power subsystems required to be OPERABLE the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.4 SR 3.8.4.7 SR 3.8.4.2 SR 3.8.4.5 SR 3.8.4.8. SR 3.8.4.3 SR 3.8.4.6	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for the Division I and Division II 125 VDC and the 250 VDC batteries shall be within limits.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each battery.

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or more batteries with one or more battery cell parameters not within Table 3.8.6-1 Category A or B limits.	A.1	Verify pilot cell electrolyte level and float voltage meet Table 3.8.6-1 Category C limits.	1 hour
		AND		
		A.2	Verify parameters for required battery cells meet Table 3.8.6-1 Category C limits.	24 hours AND Once per 7 days thereafter
		AND		
		A.3	Restore parameters for required battery cells to Table 3.8.6-1 Category A and B limits.	31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR One or more batteries with average electrolyte temperature of the representative cells not within limits. OR One or more batteries with one or more battery cell parameters for required battery cells not within Table 3.8.6-1 Category C limits.	B.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify battery cell parameters meet Table 3.8.6-1 Category A limits.	In accordance with the Surveillance Frequency Control Program
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after battery discharge < 110 V for 125 V and < 220 V for 250 V AND Once within 24 hours after battery overcharge > 150 V for 125 V and > 300 V for 250 V
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is $\geq 65°F$ for each battery.	In accordance with the Surveillance Frequency Control Program

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameter Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[b][c]	≥ 1.195	≥ 1.190 AND Average of all connected cells > 1.200	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥ 1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when on float charge and battery charging current is < 2 amps.

(c) A battery charging current of < 2 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems — Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Division 1 and Division 2 AC electrical power distribution subsystems;

b. Division 1 and Division 2 125 VDC electrical power distribution subsystems;

c. 250 VDC electrical power distribution subsystem;

d. Intake structure electrical power distribution subsystems; and

e. 125 VDC RCIC Motor Control Center (MCC).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or more AC electrical power distribution subsystems inoperable, except for the intake structure electrical power distribution subsystems.	A.1	Restore AC electrical power distribution subsystems to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a or b
B.	One or more essential 125 VDC electrical power distribution subsystems inoperable except for the RCIC MCC.	B.1	Restore the 125 VDC electrical power distribution subsystems to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a or b

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. One or both intake structure electrical power distribution subsystem(s) inoperable.	D.1 Declare the associated River Water Supply subsystem(s) inoperable.	Immediately
E. 250 VDC electrical power distribution subsystem inoperable.	E.1 Declare associated supported features inoperable.	Immediately
F. 125 VDC RCIC MCC inoperable.	F.1 Declare associated supported features inoperable.	Immediately
G. Two or more electrical power distribution subsystems inoperable that result in a loss of function, for reasons other than Condition D.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and indicated power availability to required AC and DC electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program
SR 3.8.7.2	Verify proper coordination of the LPCI Swing Bus circuit breakers.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Distribution Systems — Shutdown

LCO 3.8.8 The necessary portions of the AC and DC electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 4 and 5.
During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

----------NOTE----------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC or DC electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable. OR A.2.1 Suspend CORE ALTERATIONS. AND A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment. AND A.2.3 Initiate action to restore required AC and DC electrical power distribution subsystems to OPERABLE status. AND	Immediately Immediately Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Declare associated required shutdown cooling subsystem(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct breaker alignments and indicated power availability to required AC and DC electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.1 Refueling Equipment Interlocks

LCO 3.9.1 The refueling equipment interlocks associated with the Refuel position shall be OPERABLE.

APPLICABILITY: During in-vessel fuel movement with equipment associated with the interlocks when the reactor mode switch is in the Refuel position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required refueling equipment interlocks inoperable.	A.1 Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s).	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refuel platform position, c. Refuel platform fuel grapple, fuel loaded, d. Refuel platform fuel grapple fully retracted position, e. Refuel platform frame mounted hoist, fuel loaded, and f. Refuel platform monorail mounted hoist, fuel loaded.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod-Out Interlock

LCO 3.9.2 The refuel position one-rod-out interlock shall be OPERABLE.

APPLICABILITY: MODE 5 with the reactor mode switch in the Refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refuel position one-rod-out interlock inoperable.	A.1 Suspend control rod withdrawal. AND	Immediately
	A.2. Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in Refuel position.	In accordance with the Surveillance Frequency Control Program
SR 3.9.2.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn. ----------	
	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.3 Control Rod Position

LCO 3.9.3 All control rods shall be fully inserted.

APPLICABILITY: When loading fuel assemblies into the core.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more control rods not fully inserted.	A.1 Suspend loading fuel assemblies into the core.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify all control rods are fully inserted.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.4 Control Rod Position Indication

LCO 3.9.4 The control rod “full-in” position indication for each control rod shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each required position indication.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required control rod position indications inoperable.	A.1.1 Suspend in-vessel fuel movement. AND A.1.2 Suspend control rod withdrawal. AND A.1.3 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. OR	Immediately Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert the control rod associated with the inoperable position indicator. AND A.2.2 Initiate action to disarm the control rod drive associated with the fully inserted control rod.	Immediately Immediately

SURVEILLANCE REQUIREMENT

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify the required position indication has no “full-in” indication on each control rod that is not “full-in.”	Each time the control rod is withdrawn from the “full-in” position

3.9 REFUELING OPERATIONS

3.9.5 Control Rod OPERABILITY — Refueling

LCO 3.9.5 Each withdrawn control rod shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more withdrawn control rods inoperable.	A.1 Initiate action to fully insert inoperable withdrawn control rods.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	----------NOTE---------- Not required to be performed until 7 days after the control rod is withdrawn. ---------- Insert each withdrawn control rod at least one notch.	In accordance with the Surveillance Frequency Control Program
SR 3.9.5.2	Verify each withdrawn control rod scram accumulator pressure is $\geq$ 940 psig.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.6 Reactor Pressure Vessel (RPV) Water Level

LCO 3.9.6 RPV water level shall be ≥ 23 ft above the top of the irradiated fuel assemblies seated within the RPV.

APPLICABILITY: During movement of irradiated fuel assemblies within the RPV,
During movement of new fuel assemblies or handling of control rods within the RPV, when irradiated fuel assemblies are seated within the RPV.

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	RPV water level not within limit.	A.1	Suspend movement of fuel assemblies and handling of control rods within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify RPV water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated within the RPV.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.7 Residual Heat Removal (RHR) — High Water Level

LCO 3.9.7 One RHR shutdown cooling subsystem shall be OPERABLE; and in operation when reactor coolant temperature ≥ 150 °F.

----------NOTE----------
The required RHR shutdown cooling subsystem may not be in operation for up to 2 hours per 8 hour period.

APPLICABILITY: MODE 5 with irradiated fuel in the Reactor Pressure Vessel (RPV) and the water level ≥ 21 ft-1 inch above the top of the RPV flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required RHR shutdown cooling subsystem inoperable.	A.1 Verify by administrative means an alternate method of decay heat removal is available.	1 hour AND Once per 24 hours thereafter
B. Required Action and associated Completion Time of Condition A not met.	B.1 Suspend loading irradiated fuel assemblies into the RPV. AND	Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Initiate action to restore secondary containment to OPERABLE status. AND	Immediately
	B.3 Initiate action to restore one standby gas treatment subsystem to OPERABLE status. AND	Immediately
	B.4 Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. No RHR shutdown cooling subsystem in operation with reactor coolant temperature ≥ 150°F.	C.1 Verify reactor coolant circulation by an alternate method. AND C.2 Monitor reactor coolant temperature.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify one RHR shutdown cooling subsystem is operating when reactor coolant temperature is ≥ 150 °F.	In accordance with the Surveillance Frequency Control Program
SR 3.9.7.2	Verify required RHR shutdown cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.8 Residual Heat Removal (RHR) — Low Water Level

LCO 3.9.8 Two RHR shutdown cooling subsystems shall be OPERABLE, and one RHR shutdown cooling subsystem shall be in operation.

----------NOTE----------
The required operating shutdown cooling subsystem may not be in operation for up to 2 hours per 8 hour period.

APPLICABILITY: MODE 5 with irradiated fuel in the Reactor Pressure Vessel (RPV) and the water level < 21 ft-1 inch above the top of the RPV flange.

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or two required RHR shutdown cooling subsystems inoperable.	A.1	Verify by administrative means an alternate method of decay heat removal is available for each inoperable required RHR shutdown cooling subsystem.	1 hour AND Once per 24 hours thereafter
B.	Required Action and associated Completion Time of Condition A not met.	B.1	Initiate action to restore secondary containment to OPERABLE status.	Immediately
		AND		(continued)

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
B.	(continued)	B.2	Initiate action to restore one standby gas treatment subsystem to OPERABLE status.	Immediately
		AND		
		B.3	Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	Immediately
C.	No RHR shutdown cooling subsystem in operation.	C.1	Verify reactor coolant circulation by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
		AND		
		C.2	Monitor reactor coolant temperature.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.8.1	Verify one RHR shutdown cooling subsystem is operating.	In accordance with the Surveillance Frequency Control Program
SR 3.9.8.2	Verify RHR shutdown cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.1 System Leakage and Hydrostatic Testing Operation

LCO 3.10.1 The average reactor coolant temperature specified in Table 1.1-1 for MODE 4 may be changed to "NA," and operation considered not to be in MODE 3; and the requirements of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System — Cold Shutdown," may be suspended, to allow reactor coolant temperature > 212ºF:

- For performance of a system leakage or hydrostatic test,
- As a consequence of maintaining adequate pressure for a system leakage or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with a system leakage or hydrostatic test,

provided the following MODE 3 LCOs are met:

a. LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," Functions 1, 3, and 4 of Table 3.3.6.2-1;

b. LCO 3.6.4.1, "Secondary Containment";

c. LCO 3.6.4.2, "Secondary Containment Isolation Valves/Dampers (SCIV/Ds)"; and

d. LCO 3.6.4.3, "Standby Gas Treatment (SBGT) System."

APPLICABILITY: MODE 4 with average reactor coolant temperature $>$ 212°F.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each requirement of the LCO.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A One or more of the above requirements not met.	A.1 ----------NOTE---------- Required Actions to be in MODE 4 include reducing average reactor coolant temperature to ≤ 212°F. ---------- Enter the applicable Condition of the affected LCO. OR A.2.1 Suspend activities that could increase the average reactor coolant temperature or pressure. AND A.2.2 Reduce average reactor coolant temperature to ≤ 212°F.	 Immediately Immediately 24 hours

SURVEILLANCE		FREQUENCY
SR 3.10.1.1	Perform the applicable SRs for the required MODE 3 LCOs.	According to the applicable SRs

3.10 SPECIAL OPERATIONS

3.10.2 Reactor Mode Switch Interlock Testing

LCO 3.10.2 The reactor mode switch position specified in Table 1.1-1 for MODES 3, 4, and 5 may be changed to include the Run, Startup/Hot Standby, and Refuel position, and operation considered not to be in MODE 1 or 2, to allow testing of instrumentation associated with the reactor mode switch interlock functions, provided:

a. All control rods remain fully inserted in core cells containing one or more fuel assemblies; and

b. No CORE ALTERATIONS are in progress.

APPLICABILITY: MODES 3 and 4 with the reactor mode switch in the Run, Startup/Hot Standby, or Refuel position,
MODE 5 with the reactor mode switch in the Run or Startup/Hot Standby position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A.1 One or more of the above requirements not met.	A.1 Suspend CORE ALTERATIONS except for control rod insertion. AND A.2 Fully insert all insertable control rods in core cells containing one or more fuel assemblies. AND	Immediately 1 hour (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A (continued)	A.3.1 Place the reactor mode switch in the Shutdown position. OR A.3.2 ----------NOTE---------- Only applicable in MODE 5. ---------- Place the reactor mode switch in the Refuel position.	1 hour 1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.2.1	Verify all control rods are fully inserted in core cells containing one or more fuel assemblies.	In accordance with the Surveillance Frequency Control Program
SR 3.10.2.2	Verify no CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.3 Single Control Rod Withdrawal — Hot Shutdown

LCO 3.10.3 The reactor mode switch position specified in Table 1.1-1 for MODE 3 may be changed to include the Refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, provided the following requirements are met:

a. LCO 3.9.2, “Refuel Position One-Rod-Out Interlock”;

b. LCO 3.9.4, “Control Rod Position Indication”;

c. All other control rods are fully inserted; and

d. 1. LCO 3.3.1.1, “Reactor Protection System (RPS) Instrumentation,” MODE 5 requirements for Functions 1.a, 1.b, 7.a, 7.b, 10, and 11 of Table 3.3.1.1-1,

LCO 3.3.8.2, “Reactor Protection System (RPS) Electric Power Monitoring,” and

LCO 3.9.5, “Control Rod OPERABILITY — Refueling,”

OR

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.1.1, “SHUTDOWN MARGIN (SDM),” MODE 3 requirements, may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod.

APPLICABILITY: MODE 3 with the reactor mode switch in the Refuel position.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each requirement of the LCO.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A.1 One or more of the above requirements not met.	A.1 ----------NOTES---------- 1. Required Actions to fully insert all insertable control rods include placing the reactor mode switch in the Shutdown position. 2. Only applicable if the requirement not met is a required LCO. ---------- Enter the applicable Condition of the affected LCO.	Immediately
	OR	
	A.2.1 Initiate action to fully insert all insertable control rods.	Immediately
	AND	
	A.2.2 Place the reactor mode switch in the Shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.10.3.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs
SR 3.10.3.2	----------NOTE---------- Not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.3.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.4 Single Control Rod Withdrawal — Cold Shutdown

LCO 3.10.4 The reactor mode switch position specified in Table 1.1-1 for MODE 4 may be changed to include the Refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, and subsequent removal of the associated Control Rod Drive (CRD) if desired, provided the following requirements are met:

a. All other control rods are fully inserted;

b. 1. LCO 3.9.2, “Refuel Position One-Rod-Out Interlock,” and

LCO 3.9.4, “Control Rod Position Indication,”

OR

2. A control rod withdrawal block is inserted;

c. 1. LCO 3.3.1.1, “Reactor Protection System (RPS) Instrumentation,” MODE 5 requirements for Functions 1.a, 1.b, 7.a, 7.b, 10, and 11 of Table 3.3.1.1-1,

LCO 3.3.8.2, “Reactor Protection System (RPS) Electric Power Monitoring,” and

LCO 3.9.5, “Control Rod OPERABILITY — Refueling,”

OR

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.1.1, “SHUTDOWN MARGIN (SDM),” MODE 4 requirements, may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod.

APPLICABILITY: MODE 4 with the reactor mode switch in the Refuel position.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each requirement of the LCO.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met with the affected control rod insertable.	A.1 ----------NOTES---------- 1. Required Actions to fully insert all insertable control rods include placing the reactor mode switch in the Shutdown position. 2. Only applicable if the requirement not met is a required LCO. ---------- Enter the applicable Condition of the affected LCO.	Immediately
	OR	
	A.2.1 Initiate action to fully insert all insertable control rods.	Immediately
	AND	
	A.2.2 Place the reactor mode switch in the Shutdown position.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more of the above requirements not met with the affected control rod not insertable.	B.1 Suspend withdrawal of the control rod and removal of associated CRD. AND	Immediately
	B.2.1 Initiate action to fully insert all control rods. OR	Immediately
	B.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.4.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs
SR 3.10.4.2	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.c.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.4.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.4.4	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.b.1 requirements. ---------- Verify a control rod withdrawal block is inserted.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.5 Single Control Rod Drive (CRD) Removal — Refueling

LCO 3.10.5 The requirements of LCO 3.3.1.1, “Reactor Protection System (RPS) Instrumentation”; LCO 3.3.8.2, “Reactor Protection System (RPS) Electric Power Monitoring”; LCO 3.9.1, “Refueling Equipment Interlocks”; LCO 3.9.2, “Refuel Position One-Rod-Out Interlock”; LCO 3.9.4, “Control Rod Position Indication”; and LCO 3.9.5, “Control Rod OPERABILITY — Refueling,” may be suspended in MODE 5 to allow the removal of a single CRD associated with a control rod withdrawn from a core cell containing one or more fuel assemblies, provided the following requirements are met:

a. All other control rods are fully inserted;

b. All other control rods in a five by five array centered on the withdrawn control rod are disarmed;

c. A control rod withdrawal block is inserted and LCO 3.1.1, “SHUTDOWN MARGIN (SDM),” MODE 5 requirements may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod; and

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: MODE 5 with LCO 3.9.5 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend removal of the CRD mechanism. AND	Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert all control rods. OR A.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.5.1	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.2	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, in a five by five array centered on the control rod withdrawn for the removal of the associated CRD, are disarmed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.3	Verify a control rod withdrawal block is inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.4	Perform SR 3.1.1.1.	According to SR 3.1.1.1
SR 3.10.5.5	Verify no other CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.6 Multiple Control Rod Withdrawal — Refueling

LCO 3.10.6 The requirements of LCO 3.9.3, “Control Rod Position”; LCO 3.9.4, “Control Rod Position Indication”; and LCO 3.9.5, “Control Rod OPERABILITY — Refueling,” may be suspended, and the “full in” position indicators may be bypassed for any number of control rods in MODE 5, to allow withdrawal of these control rods, removal of associated Control Rod Drives (CRDs), or both, provided the following requirements are met:

a. The four fuel assemblies are removed from the core cells associated with each control rod or CRD to be removed;

b. All other control rods in core cells containing one or more fuel assemblies are fully inserted; and

c. Fuel assemblies shall only be loaded in compliance with an approved reload sequence.

APPLICABILITY: MODE 5 with LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend withdrawal of control rods and removal of associated CRDs. AND A.2 Suspend loading fuel assemblies. AND	Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Initiate action to fully insert all control rods in core cells containing one or more fuel assemblies. OR A.3.2 Initiate action to satisfy the requirements of this LCO.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.1	Verify the four fuel assemblies are removed from core cells associated with each control rod or CRD removed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.6.2	Verify all other control rods in core cells containing one or more fuel assemblies are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.6.3	----------NOTE---------- Only required to be met during fuel loading. ---------- Verify fuel assemblies being loaded are in compliance with an approved reload sequence.	In accordance with the Surveillance Frequency Control Program

3.10 SPECIAL OPERATIONS

3.10.7 Control Rod Testing — Operating

LCO 3.10.7 The requirements of LCO 3.1.6, “Rod Pattern Control,” may be suspended to allow performance of SDM demonstrations, control rod scram time testing, and control rod friction testing, provided:

a. The Banked Position Withdrawal Sequence requirements of SR 3.3.2.1.7 are changed to require the control rod sequence to conform to the specified test sequence.

OR

b. The RWM is bypassed; the requirements of LCO 3.3.2.1, “Control Rod Block Instrumentation,” Function 2 are suspended; and conformance to the approved control rod sequence for the specified test is verified by a second licensed operator or other qualified member of the technical staff.

APPLICABILITY: MODES 1 and 2 with LCO 3.1.6 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Suspend performance of the test and exception to LCO 3.1.6.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.7.1	----------NOTE---------- Not required to be met if SR 3.10.7.2 satisfied. ---------- Verify movement of control rods is in compliance with the approved control rod sequence for the specified test by a second licensed operator or other qualified member of the technical staff.	During control rod movement
SR 3.10.7.2	----------NOTE---------- Not required to be met if SR 3.10.7.1 satisfied. ---------- Verify control rod sequence input to the RWM is in conformance with the approved control rod sequence for the specified test.	Prior to control rod movement

3.10 SPECIAL OPERATIONS

3.10.8 SHUTDOWN MARGIN (SDM) Test — Refueling

LCO 3.10.8 The reactor mode switch position specified in Table 1.1-1 for MODE 5 may be changed to include the Startup/Hot Standby position, and operation considered not to be in MODE 2, to allow SDM testing, provided the following requirements are met:

a. LCO 3.3.1.1, “Reactor Protection System Instrumentation,” MODE 2 requirements for Functions 2.a and 2.d of Table 3.3.1.1-1;

b. 1. LCO 3.3.2.1, “Control Rod Block Instrumentation,” MODE 2 requirements for Function 2 of Table 3.3.2.1-1, with the Banked Position Withdrawal Sequence requirements of SR 3.3.2.1.7 changed to require the control rod sequence to conform to the SDM test sequence,

OR

2. Conformance to the approved control rod sequence for the SDM test is verified by a second licensed operator or other qualified member of the technical staff;

c. Each withdrawn control rod shall be coupled to the associated CRD;

d. All control rod withdrawals during out of sequence control rod moves shall be made in notch out mode;

e. No other CORE ALTERATIONS are in progress; and

f. CRD charging water header pressure $\geq$ 970 psig.

APPLICABILITY: MODE 5 with the reactor mode switch in Startup/Hot Standby position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE--------- Separate Condition entry is allowed for each control rod. ---------- One or more control rods not coupled to its associated CRD.	----------NOTE---------- Rod Worth Minimizer may be bypassed as allowed by LCO 3.3.2.1, “Control Rod Block Instrumentation,” if required, to allow insertion of inoperable control rod and continued operation. ---------- A.1 Fully insert inoperable control rod. AND A.2 Disarm the associated CRD.	 3 hours 4 hours
B. One or more of the LCO requirements not met for reasons other than Condition A.	B.1 Place the reactor mode switch in the Shutdown or Refuel position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.8.1	Perform the MODE 2 applicable SRs for LCO 3.3.1.1, Functions 2.a and 2.d of Table 3.3.1.1-1.	According to the applicable SRs
SR 3.10.8.2	----------NOTE---------- Not required to be met if SR 3.10.8.3 satisfied. ----------	
	Perform the MODE 2 applicable SRs for LCO 3.3.2.1, Function 2 of Table 3.3.2.1-1.	According to the applicable SRs
SR 3.10.8.3	----------NOTE---------- Not required to be met if SR 3.10.8.2 satisfied. ----------	
	Verify movement of control rods is in compliance with the approved control rod sequence for the SDM test by a second licensed operator or other qualified member of the technical staff.	During control rod movement
SR 3.10.8.4	Verify no other CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.8.5	Verify each withdrawn control rod does not go to the withdrawn overtravel position.	Each time the control rod is withdrawn to “full out” position AND Prior to satisfying LCO 3.10.8.c requirement after work on control rod or CRD System that could affect coupling
SR 3.10.8.6	Verify CRD charging water header pressure $\geq$ 970 psig.	In accordance with the Surveillance Frequency Control Program

4.0 DESIGN FEATURES

4.1 Site Location

The plant site, which consists of approximately 500 acres, is adjacent to the Cedar River approximately 2.5 miles northeast of the Village of Palo, Iowa. Distance from the reactor centerline to the nearest site boundary is approximately 2000 ft. The boundary of the exclusion area defined in 10 CFR 100 is delineated by the property lines. The distance to the outer boundary of the low population zone is 6 miles. The plan of the site is shown on UFSAR Figures 1.2-1 and 1.2-2.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall consist of not more than 368 fuel assemblies. Each assembly shall consist of a matrix of Zircalloy or ZIRLO fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material, and water rods. Limited substitution of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with NRC staff approved codes and methods and have been shown by tests or analyses to comply with all safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 89 cruciform shaped control rod assemblies. The control materials shall be boron carbide and hafnium metal, as approved by the NRC.

4.0 DESIGN FEATURES

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having the following limits for maximum k-infinity in the normal reactor core configuration at cold conditions and maximum lattice-average U-235 enrichment weight percent:

		k-∞	wt %
i)	7x7 and 8x8 pin arrays (Legacy Fuel Assemblies only; Holtec and PaR racks)	≤ 1.29	≤ 4.6
ii)	10x10 pin arrays (Holtec and PaR racks)	≤ 1.29	≤ 4.95

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in 9.1 of the UFSAR; and

c. A nominal 6.060 inches for HOLTEC designed and 6.625 inches for PaR designed center to center distance between fuel assemblies placed in the storage racks.

d. The Boral neutron absorber shall have a ^{10}B areal density greater than or equal to 0.0162 grams $^{10}B/cm^2$ with an uncertainty of 0.0012 grams $^{10}B/cm^2$.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.31 in the normal reactor core configuration at cold conditions;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. $k_{eff} \leq 0.90$ if dry, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR; and

d. A nominal 6.625 inch center to center distance between fuel assemblies placed in storage racks.

4.0 DESIGN FEATURES

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 831 ft. – 2 3/4 in.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 2563 fuel assemblies in a vertical orientation, including no more than 152 fuel assemblies stored in the cask pit in accordance with UFSAR Section 9.1.

The new fuel storage vault is equipped with racks for storage of up to 110 fuel assemblies in a vertical orientation.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The plant manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The plant manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affects nuclear safety.

5.1.2 The Operations Shift Manager shall be responsible for the control room command function. During any absence of the Operations Shift Manager from the control room while the unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the Operations Shift Manager from the control room while the unit is in MODE 4 or 5, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant specific titles of those personnel fulfilling the responsibilities of the positions delineated in the Technical Specifications shall be documented in the UFSAR or QA Program Description;

b. The plant manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The corporate officer with direct responsibility for the plant shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

(continued)

5.2 Organization (continued)

5.2.2 Unit Staff

The unit staff organization shall also include the following:

a. A non-licensed operator shall be assigned to the reactor when containing fuel and an additional non-licensed operator shall be assigned to the reactor when operating in MODES 1, 2, or 3.

b. Shift crew composition shall meet the requirements stipulated herein and in 10 CFR 50.54(m).

c. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.g for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

d. A person qualified to implement radiation protection procedures shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

e. Not used.

f. The Operations Manager or Operations Supervisors shall hold an SRO license.

g. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. This function is not required in MODES 4 and 5.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications referenced for comparable positions, as specified in the Florida Power and Light Company and NextEra Energy Quality Assurance Topical Report (FPL-1).

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and to NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. [Deleted]; and

e. All programs specified in Specifications 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented and maintained.

5.5.1 Offsite Dose Assessment Manual (ODAM)

a. The ODAM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODAM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating Report and Radioactive Material Release Report required by Specification 5.6.2 and Specification 5.6.3.

c. Licensee initiated changes to the ODAM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

a. Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

b. A determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent dose or setpoint calculations;

2. Shall become effective after the approval of the plant manager; and

3. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODAM as a part of or concurrent with the Radioactive Material Release Report for the period of the report in which any change in the ODAM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals (continued)

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include Core Spray, High Pressure Coolant Injection, Residual Heat Removal, Reactor Core Isolation Cooling, Reactor Water Cleanup (only to second isolation valve). Post Accident Sampling (until such time as a modification eliminates PASS as a potential leakage path), Containment Atmospheric Monitoring, Control Rod Drive (scram discharge volume only) and Liquid Radwaste (only Reactor Building Floor and Equipment Drain sump pumps, piping, and tanks up to and including collector tanks). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. System leak test requirements for each system at least once per 24 months.

The provisions of SR 3.0.2 are applicable.

5.5.3 [Deleted]

5.5.4 Radioactive Effluent Controls Program

This program, conforming to 10 CFR 50.36a, provides for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODAM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODAM;

b. Limitations on the concentrations of radioactive material released in liquid effluents from the site to unrestricted areas, conforming to ten times (10x) the concentrations listed in Appendix B, Table 2, Column 2 to 10 CFR 20.1001 – 20.2402;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents pursuant to 10 CFR 20.1302 and with the methodology and parameters in the ODAM;

(continued)

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program (continued)

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODAM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems which were used to establish compliance with the design objectives in 10 CFR 50, Appendix I, Section II be used when specified to provide reasonable assurance that releases of radioactive material in liquid and gaseous effluents be kept as low as reasonably achievable;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be limited to the following:

1. For noble gases: less than or equal to a dose rate of 500 mrem/yr to the whole body and less than or equal to a dose rate of 3000 mrem/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half lives $>$ 8 days: less than or equal to a dose rate of 1500 mrem/yr to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives $>$ 8 days in gaseous effluents released to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

5.5 Programs and Manuals (continued)

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the UFSAR Section 5.3.3, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 [Deleted]

5.5.7 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems.

The tests described in Specifications 5.5.7.a and 5.5.7.b shall be performed once per 12 months for standby service, after 720 hours of system operation, following significant painting, fire or chemical release in any ventilation zone communicating with the system, after any structural maintenance on the system housing, and after each partial or complete replacement of the HEPA filter train or charcoal adsorber, respectively.

The test described in Specification 5.5.7.c shall be performed once per 12 months for standby service, after 720 hours of system operation and following significant painting, fire or chemical release in any ventilation zone communicating with the system.

The test described in Specification 5.5.7.d shall be performed annually.

For the SBGT System only, the test described in Specification 5.5.7.e shall be performed after each complete or partial replacement of the HEPA filter bank and after any structural maintenance on the system housing.

For the SBGT System only, the test described in Specification 5.5.7.f shall be performed in conjunction with the tests described in Specification 5.5.7.c.

a. Demonstrate for each of the ESF systems that an inplace test of the HEPA filters shows a penetration and system bypass at the value specified and at the system flowrate specified below:

ESF Ventilation System	Penetration and System Bypass (%)	Flowrate (cfm)
SBGT System	< 0.1	3600 - 4400
SFU System	< 1.0	900 - 1100

(continued)

5.5 Programs and Manuals (continued)

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass at the value specified and at the system flowrate specified below:

ESF Ventilation System	Penetration and System Bypass (%)	Flowrate (cfm)
SBGT System	< 0.1	3600 – 4400
SFU System	< 1.0	900 - 1100

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52 Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and the relative humidity specified below:

ESF Ventilation System	Penetration	Relative Humidity
SBGT System	< 0.5%	≥ 95%
SFU System	< 5.0%	≥ 95%

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters (SBGT System only), and the charcoal adsorbers is less than the value specified below and at the system flowrate specified as follows:

ESF Ventilation System	Delta P (inches wg)	Flowrate (cfm)
SBGT System	< 11	3600 – 4400
SFU System	< 6	900 – 1100

e. Demonstrate that air distribution is uniform within 20% of averaged flow per unit across SBGT System HEPA filters.

f. Visually inspect the SBGT System charcoal adsorber to ensure no flow blockage has occurred.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5 Programs and Manuals (continued)

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Offgas System downstream of the recombiners and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures".

The program shall include:

a. The limits for concentrations of hydrogen in the Offgas System downstream of the recombiners and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is $\leq$ 50 curies, excluding tritium and dissolved or entrained noble gases. The liquid radwaste storage tanks in the Low-Level Radwaste Processing and Storage Facility are considered unprotected outdoor tanks.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

(continued)

5.5 Programs and Manuals (continued)

5.5.9 Diesel Fuel Oil Testing Program (continued)

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. An API gravity within limits,

2. A viscosity within limits for ASTM 2-D fuel oil, and

3. Water and sediment within limits;

b. Viscosity, water and sediment for stored ASTM 2-D fuel oil are within limits every 31 days; and

c. Total particulate concentration of the stored fuel oil is $\leq$ 10 mg/l when tested every 92 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program Testing Frequencies.

5.5.10 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of Specification 5.5.10b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5 Programs and Manuals (continued)

5.5.11 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6.

a. The SFDP shall contain the following:

1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, no concurrent loss of offsite power or no concurrent loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems (1) and (2) above is also inoperable.

(continued)

5.5 Programs and Manuals (continued)

5.5.11 Safety Function Determination Program (SFDP) (continued)

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.12 Primary Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions.

b. This program shall be in accordance with the guidelines contained in NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," and conditions and limitations specified in NEI 94-01, Revision 2-A, as modified by the following exceptions:

1. [Deleted]

2. Exemption from Section III.A of 10 CFR Part 50, Appendix J, Option B, to allow the contribution from Main Steam pathway leakage to be excluded from the overall integrated leakage rate from Type A tests.

3. Exemption from Section II.B of 10 CFR Part 50, Appendix J, Option B, to allow the contribution from Main Stream pathway leakage to be excluded from the sum of the leakage rates from Type B and Type C tests.

c. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 45.7 psig.

d. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 2.0% of primary containment air weight per day.

(continued)

5.5 Programs and Manuals (continued)

5.5.12 Primary Containment Leakage Rate Testing (continued)

e. Leakage Rate acceptance criteria are:

1. Primary Containment leakage rate acceptance criterion is ≤ 1.0 L_a. During the first startup following testing in accordance with this program, the leakage rate acceptance criteria are: ≤ 0.60 L_a for the Type B and Type C tests; and, ≤ 0.75 L_a for the Type A tests; and

2. The air lock testing acceptance criterion is overall air lock leakage rate ≤ 0.05 L_a when tested at $\geq P_a$.

f. The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.5.13 Control Building Envelope Habitability Program

A Control Building Envelope (CBE) Habitability Program shall be established and implemented to ensure that CBE habitability is maintained such that, with an OPERABLE Standby Filter Unit System, CBE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CBE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CBE and the CBE boundary.

b. Requirements for maintaining the CBE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CBE boundary into the CBE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, “Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors,” Revision 0, May 2003, and (ii) assessing CBE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

(continued)

5.5 Programs and Manuals (continued)

5.5.13 Control Building Envelope Habitability Program (continued)

d. Measurement, at designated locations, of the CBE pressure relative to all external areas adjacent to the CBE boundary during the pressurization mode of operation by one subsystem of the SFU System, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a Staggered Test Basis*. The results shall be trended and used as part of the 24 month assessment of the CBE boundary.

e. The quantitative limits on unfiltered air inleakage into the CBE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air leakage limits for hazardous chemicals must ensure that the exposure of CBE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CBE habitability, determining CBE unfiltered inleakage, and measuring CBE pressure and assessing the CBE boundary as required by paragraphs c and d, respectively.

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*A Staggered Test Basis shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during n Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

5.5 Programs and Manuals (continued)

5.5.14 Surveillance Frequency Control Program

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

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

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

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.15 Spent Fuel Pool Neutron Absorber Monitoring Program

This program provides routine monitoring and actions to ensure that the condition of Boral in the spent fuel pool racks is appropriately monitored to ensure that the Boral neutron attenuation capability described in the criticality safety analysis of UFSAR Section 9.1 is maintained. The program shall include the following:

a. Neutron attenuation in situ testing for the PaR racks shall be performed at a frequency of not more than 10 years, or more frequently based on observed trends or calculated projections of Boral degradation. The acceptance criterion for minimum Boral areal density will be that value assumed in the criticality safety analysis.

b. Neutron attenuation testing of a representative Boral coupon for the Holtec racks shall be performed at a frequency of not more than 6 years, or more frequently based on observed trends or calculated projections of Boral degradation. The acceptance criterion for minimum Boral density will be that value assumed in the criticality safety analysis.

c. Description of appropriate corrective actions for discovery on nonconforming Boral.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 DELETED

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Assessment Manual (ODAM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODAM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in Regulatory Guide 4.8. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Material Release Report

The Radioactive Material Release Report covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODAM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.4 DELETED

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. The Average Planar Linear Heat Generation Rate (APLHGR) for Specification 3.2.1;

2. The Minimum Critical Power Ratio (MCPR) for Specification 3.2.2;

3. Exclusion Region in the Power/Flow Map for Specification 3.4.1; and

4. The Minimum Critical Power Ratios (MCPR) in Table 3.3.2.1-1 for Specification 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC in General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A, (GESTAR II). The revision number is the one approved at the time the reload fuel analyses are performed.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 PAM Report

When a report is required by Condition B or F of LCO 3.3.3.1, “Post Accident Monitoring (PAM) Instrumentation,” a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method(s) of monitoring, describe the degree to which the alternate method(s) are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6 Reporting Requirements (continued)

5.6.7 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

i) Limiting Conditions for Operation Section 3.4.9, "RCS Pressure and Temperature (P/T) Limits"

ii) Surveillance Requirements Section 3.4.9, "RCS Pressure and Temperature (P/T) Limits"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

i) SIR-05-044-A, "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," Revision 1, dated June 2013.

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously transmits dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(continued)

5.7 High Radiation Area (continued)

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 <u>High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation</u>

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

(continued)

5.7 High Radiation Area (continued)

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, or personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

(continued)

5.7 High Radiation Area (continued)

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible light shall be activated at the area as a warning device.

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

UFSAR 3.1.2.2.1 (Ref. 1) and SLs ensure that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients and Abnormal Operational Transients.

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during Abnormal Operational Transients, at least 99.9% of the fuel rods in the core do not experience transition boiling.

(continued)

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The reactor vessel water level SL ensures that adequate core cooling capability is maintained during all MODES of reactor operation. Establishment of ECCS initiation setpoints higher than the SL provides margin to the SL but is independent of the SL.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and Abnormal Operational Transients. The reactor core SLs are established to preclude violation of the fuel design criterion that a MCPR limit is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with the other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR limit.

2.1.1.1 Fuel Cladding Integrity

GE critical power correlations are applicable for all critical power calculations at pressures $\geq$ 686 psig and core flows $\geq$ 10% of rated flow. For operation at low pressures or low flows, another basis is used, as follows:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be > 4.5 psi. Analyses (Ref. 2) show that with a bundle flow of 28 x 10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > 43% RTP. Thus, a THERMAL POWER limit of 21.7% RTP for reactor pressure < 686 psig is conservative.

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which transition boiling is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid transition boiling, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties used in the determination of the MCPR SL and of the nominal values of the parameters used in the MCPR SL statistical analysis.

For SLO, the SLMCPR is greater to account for the increased uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

2.1.1.3 Reactor Vessel Water Level

During MODES 1 and 2 the reactor vessel water level is required to be above the top of the active fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes < 2/3 of the core height. The reactor vessel water level SL is used to initiate the actions of 10 CFR 50.36(c)(1). This limit is not used as a reference point for any RPS or ECCS automatic actuation setpoints. These setpoints ensure automatic actuation of safety functions that maintain fuel cladding integrity even if the reactor vessel water level SL is violated. The reactor vessel water level SL has been established at 15 inches above the top of the active irradiated fuel to provide a point that can be monitored and to also provide adequate SLs for effective action.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

APPLICABILITY

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident Source Term," limits (Ref. 3). Therefore, it is required to fully insert all insertable control rods and restore compliance with the SLs within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

When operating in MODES 1 or 2, it is expected that a manual scram would be required to insert all insertable control rods within the two hour time limit. When operating in MODES 3, 4, or 5, all insertable control rods could possibly be inserted manually within the two hour time limit.

REFERENCES

1. UFSAR 3.1.2.2.1.

2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved revision).

3. 10 CFR 50.67.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on reactor steam dome pressure protects the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. According to UFSAR Sections 3.1.2.2.5, "Criterion 14 - Reactor Coolant Pressure Boundary," and 3.1.2.2.6, "Criterion 15 - Reactor Coolant System Design" (Ref. 1), the Reactor Coolant Pressure Boundary (RCPB) shall be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation and Abnormal Operational Transients.

During normal operation and Abnormal Operational Transients, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "System Leakage and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of the Inservice Inspection Program (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB, reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 50.67, "Accident Source Term" (Ref. 4). If this occurred in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure-High Function have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The SL is equal to the most limiting transient pressure allowed by the applicable codes for the reactor pressure vessel and Reactor Coolant System (RCS) piping. Since the SL is measured in the reactor steam dome, the SL is adjusted to ensure the most limiting transient pressure allowed by the applicable code is not exceeded at the lowest elevation of the RCS or the RPV.

The reactor pressure vessel (design pressure of 1250 psig at 575°F is designed to Section III of the ASME, Boiler and Pressure Vessel Code, 1965 Edition, including Addenda through the summer of 1967 and various code cases (Ref. 5), which permits a maximum pressure transient of 110% of design pressure (110% x 1250 psig = 1375 psig). The RCS piping (suction: 1150 psig at 562°F; discharge 1325 psig at 562°F) is designed to the USAS, Nuclear Power Piping Code, Section B31.1, 1967 Edition (Ref. 6) which permits a maximum pressure transient of 120% of design pressure (suction: 120% x 1150 psig = 1380 psig; discharge: 120% x 1325 psig = 1590 psig) during 1% of the operating period.

To determine the SL, the maximum pressure transient limits allowed by the applicable codes were adjusted to account for the added pressure due to elevation sensed at the lowest points in the reactor pressure vessel and reactor coolant system piping. To achieve the most conservative pressure adjustment due to elevation, it was assumed the reactor pressure vessel was completely flooded with cold water. The highest elevation (head spray line flange) of the reactor pressure vessel is 841.2 feet. The lowest elevation (CRD housing flange) of the reactor pressure vessel is 760.8 feet. The lowest elevation (drain line off the bottom of the 'A' recirculation loop) of the RCS piping is 743.4 feet.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum steam dome pressure allowed by the applicable code for the reactor pressure vessel is 1340 psig (1375 psig - [(841.2 ft - 760.8 ft) x 0.433 psi/ft] = 1340 psig). The maximum steam dome pressure allowed by the applicable code for the RCS piping is 1337.7 psig (1380 psig - [(841.2 ft - 743.4 ft) x 0.433 psi/ft] = 1337.7 psig). Therefore, the most limiting steam dome pressure allowed is 1337.7 psig. The SL is conservatively rounded to 1335 psig, which corresponds to the maximum steam dome pressure allowed by the applicable code for the RCS.

SAFETY LIMITS

The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 120% of design pressures of 1150 psig for suction piping and 1325 psig for discharge piping. The most limiting of these allowances is the 120% of the suction piping design pressures; therefore, the SL on maximum allowable RCS pressure is established at 1335 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT VIOLATIOINS

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident Source Term," limits (Ref. 4). Therefore, it is required to fully insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Sections 3.1.2.2.5 and 3.1.2.2.6.

2. ASME, Boiler and Pressure Vessel Code, Section III, 1965 Edition, Addenda Summer 1967, Article 9.

3. Inservice Inspection Program, Latest Approved Edition.

4. 10 CFR 50.67.

5. ASME, Boiler and Pressure Vessel Code, Section III, 1965 Edition, Addenda Summer 1967 and Code Cases 1332-4, 1335-2 and 1420.

6. ASME, USAS, Nuclear Power Piping Code, Section B31.1, 1967 Edition.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs

LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action

(continued)

BASES

LCO 3.0.2 (continued)

specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

(continued)

BASES (continued)

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

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BASES

LCO 3.0.3 (continued)

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 4 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 4, or other applicable MODE, is not reduced. For example, if MODE 2 is reached in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for reaching MODE 3 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, and 3, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 4 and 5 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.8, "Spent Fuel Storage Pool Water Level." LCO 3.7.8 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel

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BASES

LCO 3.0.3 (continued)

storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.8 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.8 of "Suspend movement of irradiated fuel assemblies in the spent fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement

(continued)

BASES

LCO 3.0.4 (continued)

10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses Revision 4A of NUMARC 93-01 dated April 2011, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into the through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the

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BASES

LCO 3.0.4 (continued)

risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant System Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2 or MODE 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

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BASES

LCO 3.0.4 (continued)

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

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BASES

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability.

However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.11, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or

(continued)

BASES

LCO 3.0.6 (continued)

compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained.

A loss of safety function may exist when a support system is inoperable, and:

A. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or (EXAMPLE B3.0.6-1)

B. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or (EXAMPLE B3.0.6-2)

C. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable. (EXAMPLE B3.0.6-3)

EXAMPLE B3.0.6-1
If System 2 of Train A is inoperable, and System 5 of Train B is operable, a loss of safety function exists in supported System 5.

EXAMPLE B3.0.6-2
If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11 which is in turn supported by System 5.

EXAMPLE B3.0.6-3
If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10, and 11.

If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

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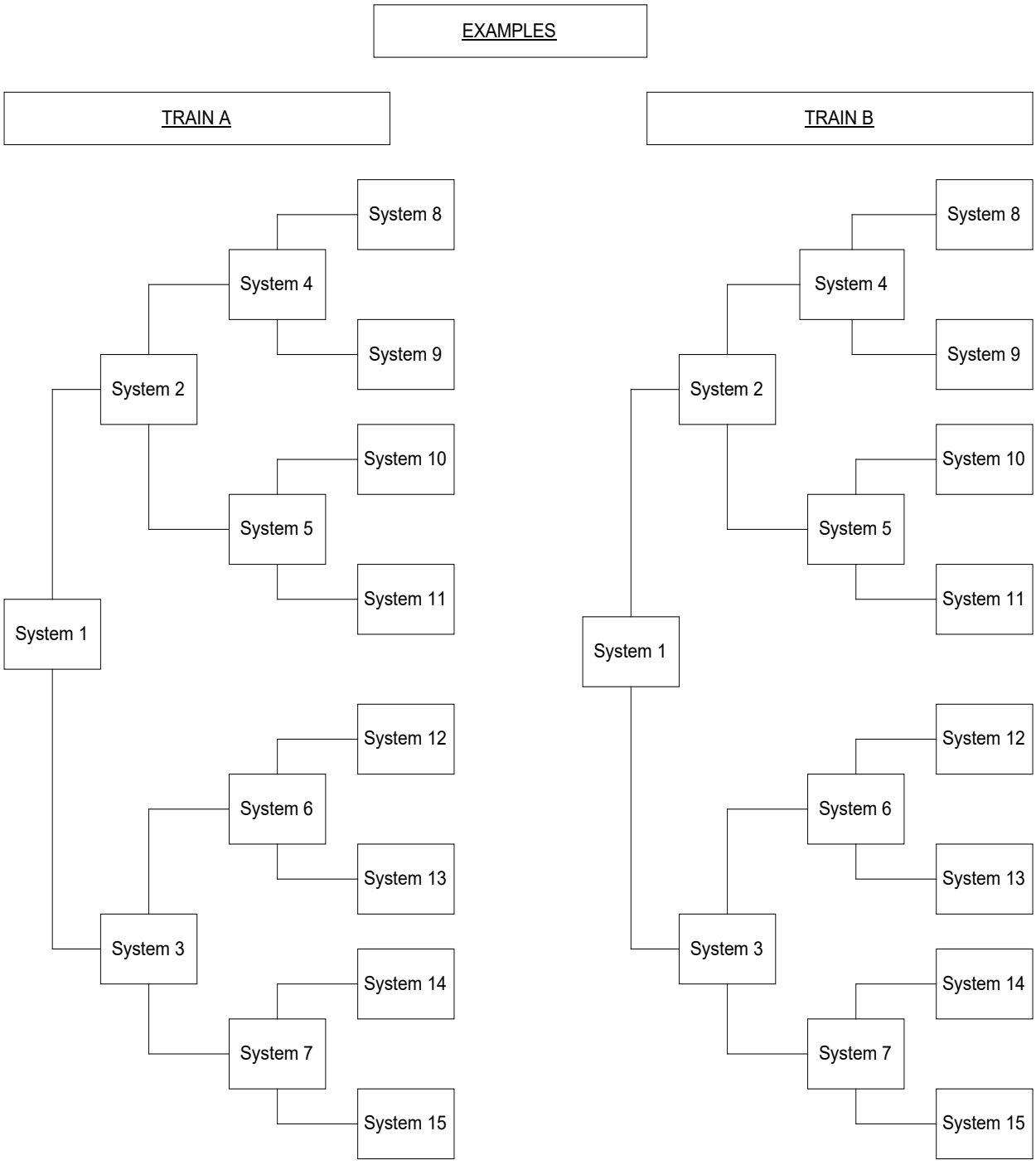
BASES

LCO 3.0.6
(continued)



BASES

LCO 3.0.6 (continued)

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to perform the special test or operation will remain in effect.

(continued)

BASES

LCO 3.0.7 (continued)

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO's ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system’s LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

(continued)

BASES

LCO 3.0.8 (continued)

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.9

LCO 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

(continued)

BASES

LCO 3.0.9 (continued)

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

(continued)

BASES

LCO 3.0.9 (continued)

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Regulatory Guide 1.160 endorses Revision 4A of NUMARC 93-01 dated April 2011, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

The HPCI (High Pressure Coolant Injection) and RCIC (Reactor Core Isolation Cooling) systems are single train systems for injecting makeup water into the reactor during an accident or transient event. The RCIC system is not a safety system, nor required to operate during a transient, therefore, it does not have to meet the single failure criterion. The HPCI system provides backup in case of a RCIC system failure. The ADS (Automatic Depressurization System) and low pressure ECCS coolant injection provide the core cooling function in the event of failure of the HPCI system during an accident. Thus, for the purposes of LCO 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and LCO 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

(continued)

BASES

LCO 3.0.9 (continued)

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Surveillance may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

(continued)

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 800 psi. However, if other appropriate testing is satisfactorily completed, the control rod can be considered OPERABLE. This allows startup to proceed to reach 800 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

(continued)

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by TS, and the SR includes a Note in the Frequency stating, "SR 3.0.2 is not applicable."

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

(continued)

BASES

SR 3.0.3 (continued)

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity. SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuraton changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of

(continued)

BASES

SR 3.0.3 (continued)

personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

(continued)

BASES

SR 3.0.4 (continued)

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed per SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2 or MODE 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

(continued)

BASES

SR 3.0.4 (continued)

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

SDM requirements are specified to ensure:

a. The reactor can be made subcritical from all operating conditions and transients and Design Basis Accidents;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits; and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

These requirements are satisfied by the control rods, as described in the UFSAR (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE SAFETY ANALYSES

The Control Rod Drop Accident (CRDA) analysis (Refs. 2 and 3) assumes the core is subcritical with the highest worth control rod withdrawn. Typically, the first control rod withdrawn has a very high reactivity worth and, should the core be critical during the withdrawal of the first control rod, the consequences of a CRDA could exceed the fuel damage limits for a CRDA (see Bases for LCO 3.1.6, "Rod Pattern Control"). Also, SDM is assumed as an initial condition for the control rod removal error during refueling (Ref. 4) and fuel assembly insertion error during refueling (Ref. 5) accidents. The analysis of these reactivity insertion events assumes the refueling interlocks are OPERABLE when the reactor is in the refueling mode of operation. These interlocks prevent the withdrawal of more than one control rod from the core during refueling. (Special consideration and requirements for multiple control rod withdrawal during refueling are covered in Special Operations LCO 3.10.6, "Multiple Control Rod Withdrawal-□Refueling.") The analysis assumes this condition is acceptable since the core will be shut down with the highest worth control rod withdrawn, if adequate SDM has been demonstrated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Prevention or mitigation of reactivity insertion events is necessary to limit energy deposition in the fuel to prevent significant fuel damage, which could result in undue release of radioactivity. Adequate SDM ensures inadvertent criticalities and potential CRDAs involving high worth control rods (namely the first control rod withdrawn) will not cause significant fuel damage.

SDM satisfies Criterion 2 of the 10 CFR 50.36(c)(2)(ii).

LCO

The specified SDM limit accounts for the uncertainty in the demonstration of SDM by testing. Separate SDM limits are provided for testing where the highest worth control rod is determined analytically or by measurement. This is due to the reduced uncertainty in the SDM test when the highest worth control rod is determined by measurement. When SDM is demonstrated by calculations not associated with a test (e.g., to confirm SDM during the fuel loading sequence), additional margin is included to account for uncertainties in the calculation. To ensure adequate SDM during the design process, a design margin is included to account for uncertainties in the design calculations (Ref. 6).

APPLICABILITY

In MODES 1 and 2, SDM must be provided because subcriticality with the highest worth control rod withdrawn is assumed in the CRDA analysis (Ref. 2). In MODES 3 and 4, SDM is required to ensure the reactor will be held subcritical with margin for a single withdrawn control rod. SDM is required in MODE 5 to prevent an open vessel, inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies or a fuel assembly insertion error (Ref. 5).

(continued)

BASES (continued)

ACTIONS

A.1

With SDM not within the limits of the LCO in MODE 1 or 2, SDM must be restored within 6 hours. Failure to meet the specified SDM may be caused by a control rod that cannot be inserted. The allowed Completion Time of 6 hours is acceptable, considering that the reactor can still be shut down, assuming no failures of additional control rods to insert, and the low probability of an event occurring during this interval.

B.1

If the SDM cannot be restored, the plant must be brought to MODE 3 in 12 hours, to prevent the potential for further reductions in available SDM (e.g., additional stuck control rods). The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

C.1

With SDM not within limits in MODE 3, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This Action is applicable for situations such as when a Required Action results in the reactor mode switch being placed in the shutdown position and not all insertable control rods have properly inserted, with SDM not met. This Action is also specifically applicable to the one rod withdrawn condition. Although the single control rod withdrawn condition is covered by Section 3.10 (Special Operations), the SDM limits of LCO 3.1.1 are still applicable. Therefore, the specified Required Action for SDM not within limits to insert all insertable control rods is appropriate and results in the least reactive condition for the core.

D.1, D.2, D.3, and D.4

With SDM not within limits in MODE 4, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This Action is applicable for situations such as when

(continued)

BASES

ACTIONS D.1, D.2, D.3, and D.4 (continued)

a Required Action results in the reactor mode switch being placed in the shutdown position and not all insertable control rods have properly inserted, with SDM not met. This Action is also specifically applicable to the one rod withdrawn condition. Although the single control rod withdrawn condition is covered by Section 3.10 (Special Operations), the SDM limits of LCO 3.1.1 are still applicable. Therefore, the specified Required Action for SDM not within limits to insert all insertable control rods is appropriate and results in the least reactive condition for the core. Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one Standby Gas Treatment (SBGT) subsystem is OPERABLE; and secondary containment isolation capability for each associated secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases is available (i.e., at least one secondary containment isolation valve or damper and associated instrumentation are OPERABLE, or other acceptable administrative controls to assure isolation capability. These administrative controls consist of stationing a dedicated operator who is in continuous communications with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.) OPERABILITY may be verified by an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

(continued)

BASES

ACTIONS (continued)

E.1, E.2, E.3, E.4, and E.5

With SDM not within limits in MODE 5, the operator must immediately suspend CORE ALTERATIONS that could reduce SDM (e.g., insertion of fuel in the core or the withdrawal of control rods). Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Inserting control rods or removing fuel from the core will reduce the total reactivity and are therefore excluded from the suspended actions.

Action must also be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies have been fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore do not have to be inserted.

Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one SBGT subsystem is OPERABLE; and secondary containment isolation capability for each associated secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., at least one secondary containment isolation valve or damper and associated instrumentation are OPERABLE, or other acceptable administrative controls to assure isolation capability. These administrative controls consist of stationing a dedicated operator who is in continuous communications with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.). If CORE ALTERATIONS were in progress, secondary containment, one SBGT subsystem and secondary containment isolation capability would already be OPERABLE since OPERABILITY of these systems is a prerequisite for performing CORE ALTERATIONS. It is the intent of Required Actions E.3, E.4 and E.5 to maintain these systems OPERABLE until SDM can be restored. Therefore, a verification of the OPERABILITY of secondary containment, one SBGT subsystem and secondary containment isolation capability is required within one hour. OPERABILITY may be verified by an administrative check, by

(continued)

BASES

ACTIONS

E.1, E.2, E.3, E.4, and E.5 (continued)

examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances as needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Action must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

Adequate SDM must be verified to ensure that the reactor can be made subcritical from any initial operating condition. This can be accomplished by a test, an evaluation, or a combination of the two. Adequate SDM is demonstrated before or during the first startup after fuel movement, shuffling within the reactor pressure vessel, or control rod replacement. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value must be decreased by "R", which is the difference between the calculated value of BOC core reactivity during the operating cycle and the calculated maximum core reactivity. If the value of R is zero (that is, BOC is the most reactive point in the cycle), no correction to the BOC measured value is required (Ref. 7). For the SDM verifications that rely solely on calculation of the highest worth control rod, additional margin (0.10% $\Delta k/k$) must be added to the SDM limit of 0.28% $\Delta k/k$ to account for uncertainties in the calculation.

The SDM may be verified during an in sequence control rod withdrawal, in which the highest worth control rod is analytically determined, or during local criticals, where the highest worth control rod is determined by testing. Local critical tests require the withdrawal of out of sequence control rods. This testing would therefore require bypassing of the rod worth minimizer to allow the out of sequence withdrawal, and therefore additional requirements must be met (see "Special Operations" LCO 3.10.7, "Control Rod Testing-Operating").

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and have appropriate verification.

During Modes 3 and 4, analytical calculation of SDM may be used to assure the requirements of SR 3.1.1.1 are met. During MODE 5, adequate SDM is required to ensure that the reactor does not reach criticality during control rod withdrawals. An evaluation of each in-vessel fuel movement during fuel loading (including shuffling fuel within the core) is required to ensure adequate SDM is maintained during refueling. For example, bounding evaluations that verify adequate SDM for the most reactive configurations during the refueling may be performed to verify acceptability of the entire fuel movement sequence. These bounding evaluations include additional margins to the associated uncertainties. Spiral offload/reload sequences inherently satisfy the SR, provided the fuel assemblies are reloaded in the same configuration analyzed for the new cycle. Removing fuel from the core will always result in an increase in SDM.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.

2. UFSAR, Section 15.2.4.

3. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Revision as specified in the COLR.

4. UFSAR, Section 15.1.4.3.

5. UFSAR, Section 15.1.4.4.1.

6. UFSAR, Section 4.3.2.4.1.

7. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Section 3.2.4.1, Revision as specified in the COLR.

(continued)

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with the UFSAR (Ref. 1), reactivity shall be controllable such that subcriticality is maintained under cold conditions and acceptable fuel design limits are not exceeded during normal operation and abnormal operational transients. Therefore, reactivity anomaly is used as a measure of the predicted versus measured (i.e., monitored) core reactivity during power operation. The continual confirmation of core reactivity is necessary to ensure that the Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity anomaly could be the result of unanticipated changes in fuel reactivity or control rod worth or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in assuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers, producing zero net reactivity.

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel loaded in the previous cycles provide excess positive reactivity beyond that required to sustain steady state operation at the beginning of cycle (BOC). When the reactor is critical at RTP and operating moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, and whatever neutron poisons (mainly xenon and samarium) that are

(continued)

BASES

BACKGROUND (continued)

present in the fuel. The predicted core reactivity, as represented by core k_{eff}, is calculated by a 3D core simulator code as a function of cycle exposure. This calculation is performed for projected operating states and conditions throughout the cycle. The monitored core k_{eff} is calculated by the core monitoring system at actual plant conditions and is compared to the predicted value at the same cycle exposure.

APPLICABLE SAFETY ANALYSES

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod drop accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted core k_{eff} for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict core k_{eff} may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the measured core k_{eff} from the predicted core k_{eff} that develop during fuel depletion may be an indication that the assumptions of the DBA and transient analyses are no longer valid, or that an unexpected change in core conditions has occurred.

Reactivity anomalies satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The reactivity anomaly limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. Large differences between monitored and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the "Nuclear Design Methodology" are larger than expected. A limit on the difference between the monitored and the predicted core k_{eff} of ± 1% Δk/k has been established based on engineering judgment. A > 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

APPLICABILITY

In MODE 1, most of the control rods are withdrawn and steady state operation is typically achieved. Under these conditions, the comparison between predicted and monitored core reactivity provides an effective measure of the reactivity anomaly. In MODE 2, control rods are typically being withdrawn during a startup. In MODES 3 and 4, all control rods are fully inserted and therefore the reactor is in the least reactive state, where monitoring core reactivity is not necessary. In MODE 5, fuel loading results in a continually changing core reactivity. SDM requirements (LCO 3.1.1) ensure that fuel movements are performed within the bounds of the safety analysis, and an SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, shuffling). The SDM test, required by LCO 3.1.1, provides a direct comparison of the predicted and monitored core reactivity at cold conditions; therefore, reactivity anomaly is not required during these conditions.

ACTIONS

A.1

Should an anomaly develop between measured and predicted core reactivity, the core reactivity difference must be restored to within the limit to ensure continued operation is within the core design assumptions. Restoration to within the limit could be performed by an evaluation of the core design and safety analysis to determine the reason for the anomaly. This evaluation normally

(continued)

BASES

ACTIONS

A.1 (continued)

reviews the core conditions to determine their consistency with input to design calculations. Measured core and process parameters are also normally evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models may be reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Verifying the reactivity difference between the monitored and predicted core k_{eff} is within the limits of the LCO provides added assurance that plant operation is maintained within the assumptions of the DBA and transient analyses. The Plant Process Computer calculates the core k_{eff} for the reactor conditions obtained from plant instrumentation. A comparison of the monitored core k_{eff} to the predicted core k_{eff} at the same cycle exposure is used to calculate the reactivity difference. The comparison is required when the core reactivity has potentially changed by a significant amount. This may occur following a refueling in which new fuel assemblies are loaded, fuel assemblies are shuffled within the core, or control rods are replaced or shuffled. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1 (continued)

subsequent replacement with a new control rod or a control rod from another core location. Also, core reactivity changes during the cycle. The 24 hour interval after reaching equilibrium conditions following a startup is based on the need for equilibrium xenon concentrations in the core, such that an accurate comparison between the monitored and predicted core k_{eff} can be made. For the purposes of this SR, the reactor is assumed to be at equilibrium conditions when steady state operations (no control rod movement or core flow changes) at $\geq$ 75% RTP have been obtained. Additionally, the Reactor Engineer or individual fulfilling this role will normally be involved with determining equilibrium xenon conditions. The 1000 MWD/T Frequency was developed, considering the relatively slow change in core reactivity with exposure and operating experience related to variations in core reactivity. This comparison requires the core to be operating at power levels which minimize the uncertainties and measurement errors, in order to obtain meaningful results. Therefore, the comparison is only done when in MODE 1.

REFERENCES

1. UFSAR, Sections 3.1.2.3.7, 3.1.2.3.9, and 3.1.2.3.10.
2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Control Rod OPERABILITY

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, which is the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes to ensure under conditions of normal operation, including anticipated operational transients, that specified acceptable fuel design limits are not exceeded. In addition, the control rods provide the capability to hold the reactor core subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. The CRD System is designed to satisfy the requirements specified in the UFSAR (Ref. 1).

The CRD System consists of 89 locking piston control rod drive mechanisms (CRDMs) and a hydraulic control unit for each drive mechanism. The locking piston type CRDM is a double-acting hydraulic piston, which uses condensate water as the operating fluid. Accumulators provide additional energy for scram. An index tube and piston, coupled to the control rod, are locked at fixed increments by a collet mechanism. The collet fingers engage notches in the index tube to prevent unintentional withdrawal of the control rod, but without restricting insertion.

This Specification, along with LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators," ensure that the performance of the control rods in the event of a Design Basis Accident (DBA) or transient meets the assumptions used in the safety analyses of References 2, 3, and 4.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in the evaluations involving control rods are presented in References 2, 3, and 4. The control rods provide the primary means for rapid reactivity control (reactor scram), for maintaining the reactor subcritical and for limiting the potential effects of reactivity insertion events caused by malfunctions in the CRD System. (e.g., the control rod velocity limiter). The capability to insert the control rods provides

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BASES

APPLICABLE SAFETY ANALYSES (continued)

assurance that the assumptions for scram reactivity in the DBA and transient analyses are not violated. Since the SDM ensures the reactor will be subcritical with the highest worth control rod withdrawn (assumed single failure), the additional failure of a second control rod to insert, if required, could invalidate the demonstrated SDM and potentially limit the ability of the CRD System to hold the reactor subcritical. If the control rod is stuck at an inserted position and becomes decoupled from the CRD, a control rod drop accident (CRDA) can possibly occur. Therefore, the requirement that all control rods be OPERABLE ensures the CRD System can perform its intended function.

The control rods also protect the fuel from damage which could result in release of radioactivity. The limits protected are the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), and the fuel damage limit (see Bases for LCO 3.1.6, "Rod Pattern Control") during reactivity insertion events.

The negative reactivity insertion (scram) provided by the CRD System provides the analytical basis for determination of plant thermal limits and provides protection against fuel damage limits during a CRDA. The Bases for LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6 discuss in more detail how the SLs are protected by the CRD System.

Control rod OPERABILITY satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of an individual control rod is based on a combination of factors, primarily, the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator OPERABILITY is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring

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BASES

LCO (continued)

a control rod inoperable. Although not all control rods are required to be OPERABLE to satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the DBA and transient analyses.

APPLICABILITY

In MODES 1 and 2, the control rods are assumed to function during a DBA or transient and are therefore required to be OPERABLE in these MODES. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions. Control rod requirements in MODE 5 are located in LCO 3.9.5, "Control Rod OPERABILITY-Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable control rod. Complying with the Required Actions may allow for continued operation, and subsequent inoperable control rods are governed by subsequent Condition entry and application of associated Required Actions.

A.1, A.2, A.3, and A.4

A control rod is considered stuck if it will not insert by either CRD drive water or scram pressure. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted. The Required Actions are modified by a Note, which allows the Rod Worth Minimizer (RWM) to be bypassed if required to allow continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis. With one withdrawn control rod stuck, the local scram reactivity rate assumptions may not be met if the stuck control rod separation criteria are not met. Therefore, a verification that the separation criteria are met must be performed immediately. The separation criteria are not met if a) the stuck control rod occupies

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BASES

ACTIONS A.1, A.2, A.3, and A.4 (continued)

a location adjacent to two "slow" control rods, b) the stuck control rod occupies a location adjacent to one "slow" control rod, and the one "slow" control rod is also adjacent to another "slow" control rod, or c) the stuck control rod occupies a location adjacent to one "slow" control rod when there is another pair of "slow" control rods adjacent to one another. The description of "slow" control rod is provided in LCO 3.1.4, "Control Rod Scram Times." In addition, the associated control rod drive must be disarmed in 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable time to perform the Required Action in an orderly manner. The control rod must be isolated from both scram and normal insert and withdraw pressure. Isolating the control rod from scram and normal insert and withdraw pressure prevents damage to the CRDM. The control rod must be isolated by isolating the hydraulic control unit from the scram and normal insert and withdraw pressure, while still maintaining cooling water to the CRD.

Monitoring of the insertion capability of each withdrawn control rod must also be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM. SR 3.1.3.2 performs periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The allowed Completion Time of 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

(continued)

BASES

ACTIONS

A.1, A.2, A.3 and A.4 (continued)

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 5).

B.1

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. During the 3 hour time limit, attempts to re-couple the rod, by inserting the

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

rod and withdrawing it to the "full-out" position to verify that the rod does not go to the "overtravel" position, may be made. However, numerous attempts to re-couple the rod should be avoided to prevent further damage to the rod or drive. If the rod can not be re-coupled, inserting the control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At $\leq$ 10% RTP, the generic Banked Position Withdrawal Sequence (BPWS) analysis (Ref. 5) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when > 10% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

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BASES

ACTIONS (continued)

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, by use of TIP traces, by alternate rod position determination methods, or by the use of other appropriate methods. The Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.3.2

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These Surveillances are not required when THERMAL POWER is less

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

than or equal to 20% RTP since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). Partially and fully withdrawn control rods are tested periodically, based on the potential power reduction required to allow the control rod movement. Furthermore, the Frequency takes into account operating experience related to changes in CRD performance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. At any time, if a control rod is immovable (e.g., due to an inoperable insert or withdrawn solenoid valve), a determination of that control rod's ability to be moved with scram pressure OPERABILITY must be made and appropriate action taken.

This SR is modified by a Note that allows 31 days after withdrawal of the control rod and increasing power to above 20% RTP, to perform the Surveillance. This acknowledges that the control rod must be first withdrawn and THERMAL POWER must be increased to above 20% RTP before performance of the Surveillance, and therefore the Notes avoid potential conflicts with SR 3.0.3 and SR 3.0.4.

SR 3.1.3.3

Verifying that the scram time for each control rod to notch position 04 is $\leq$ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1 and SR 3.1.4.2. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.3 (continued)

demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.4

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying a withdrawn control rod does not go to the withdrawn overtravel position. The overtravel position feature provides a positive check on the coupling integrity since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This includes control rods inserted one notch and then returned to the "full out" position during the performance of SR 3.1.3.2. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

REFERENCES

1. UFSAR, Sections 3.1.2.3.7, 3.1.2.3.8, 3.1.2.3.9, and 3.1.2.3.10
2. UFSAR, Section 4.3.3.
3. UFSAR, Section 5.2.2 and Appendix 5B.
4. UFSAR, Section 15.0.
5. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System controls reactivity changes during Abnormal Operational Transients and Design Basis Accidents (DBAs) to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrammed by positive means using hydraulic pressure exerted on the CRD piston.

When a scram signal is initiated, control air is vented from the scram valves, allowing them to open by spring action. Opening the exhaust valve reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator pressure, or reactor pressure is applied to the bottom of the piston. Since the notches in the index tube are tapered on the lower edge, the collet fingers are forced open by cam action, allowing the index tube to move upward without restriction because of the high differential pressure across the piston. As the drive moves upward and the accumulator pressure reduces below the reactor pressure, a ball check valve opens, letting the reactor pressure complete the scram action. If the reactor pressure is low, such as during startup, the accumulator will fully insert the control rod in the required time without assistance from reactor pressure.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 2, 3, and 4. The DBA and transient analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Other distributions of scram times (e.g., several control rods scramming slower than the average time with several control rods scramming faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The scram function of the CRD System protects the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded. Above 800 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL, during the analyzed limiting power transient. Below 800 psig, the scram function is assumed to perform during the control rod drop accident (Ref. 5) and, therefore, also provides protection against violating fuel damage limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). For the reactor vessel overpressure protection analysis (Ref. 3), the scram function, along with the safety/relief valves, ensure that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control rod scram times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The scram times specified in Table 3.1.4-1 are required to ensure that the scram reactivity assumed in the DBA and transient analysis is met (Ref. 6). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.4-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows up to approximately 7% of the control rods (e.g., 89 x 7% $\approx$ 6) to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens ("dropout") as the index tube travels upward. Verification of the specified scram times in Table 3.1.4-1 is accomplished through

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BASES

LCO (continued)

measurement of the "dropout" times. To ensure that local scram reactivity rates are maintained within acceptable limits, no more than two of the allowed "slow" control rods may occupy adjacent locations.

Table 3.1.4-1 is modified by two Notes which state that control rods with scram times not within the limits of the table are considered "slow" and that control rods with scram times > 7 seconds are considered inoperable as required by SR 3.1.3.3.

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, the control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY-Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analyses. Therefore, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

The two SRs of this LCO are modified by a Note stating that during a single control rod scram time surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated (i.e., charging valve closed), the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on an assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure $\geq$ 800 psig demonstrates acceptable scram times for the transients analyzed in References 3 and 4.

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure $\geq$ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following a refueling or after a shutdown $\geq$ 120 days, control rods are required to be tested before exceeding 40% RTP following the shutdown. In the event fuel movement is limited to selected core cells, only those CRDs associated with the core cells affected by the fuel movements are required to be scram time tested in accordance with SR 3.1.4.2. However, if the reactor remains shutdown $\geq$ 120 days, all control rods are required to be scram time tested. This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by work on control rods or the CRD System.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.2

When work that could affect the scram insertion time is performed on a control rod or CRD System, or when fuel movement within the reactor pressure vessel occurs, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure $\geq$ 800 psig. Alternatively, a control rod scram test during hydrostatic pressure testing could also satisfy both criteria. When only fuel movement occurs, then only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

REFERENCES

1. UFSAR, Section 3.1.2.2.1
2. UFSAR, Section 4.3.3.
3. UFSAR, Section 5.2.2 and Appendix 5B.
4. UFSAR, Section 15.0.
5. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Section 3.2.4.1 Revision as specified in the COLR.
6. Letter from R.F. Janecek (BWROG) to R.W. Starostecki (NRC), "BWR Owners Group Revised Reactivity Control System Technical Specifications," BWROG-8754, September 17, 1987.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Control Rod Scram Accumulators

BASES

BACKGROUND

The control rod scram accumulators are part of the Control Rod Drive (CRD) System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a control rod at any reactor vessel pressure. The accumulator is a hydraulic cylinder with a free floating piston. The piston separates the water used to scram the control rods from the nitrogen, which provides the required energy. The scram accumulators are necessary to scram the control rods within the required insertion times of LCO 3.1.4, "Control Rod Scram Times."

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 1, 2, and 3. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. OPERABILITY of each individual control rod scram accumulator, along with LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.4, ensures that the scram reactivity assumed in the DBA and transient analyses can be met. The existence of an inoperable accumulator may invalidate prior scram time measurements for the associated control rod.

The scram function of the CRD System, and therefore the OPERABILITY of the accumulators, protects the MCPR Safety Limit (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). In addition, the scram function at low reactor vessel pressure (i.e., startup conditions) provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control").

Control Rod Scram Accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.

APPLICABILITY

In MODES 1 and 2, the scram function is required for mitigation of DBAs and transients, and therefore the scram accumulators must be OPERABLE to support the scram function. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram accumulator OPERABILITY during these conditions. Requirements for scram accumulators in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable accumulator. Complying with the Required Actions may allow for continued operation and subsequent inoperable accumulators governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

With one control rod scram accumulator inoperable and the reactor steam dome pressure $\geq$ 900 psig, the control rod may be declared "slow," since the control rod will still scram at the reactor operating pressure but may not satisfy the required scram times in Table 3.1.4-1.

Required Action A.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control rod scram time was within the limits of Table 3.1.4-1 during the last scram time surveillance. Otherwise, the control rod would already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action A.2) and LCO 3.1.3 is entered. This would result in requiring the affected control rod to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 8 hours is reasonable, based on the large number of control rods available to provide the scram function and the ability of the affected control rod to scram only with reactor pressure at high reactor pressures.

B.1, B.2.1, and B.2.2

With two or more control rod scram accumulators inoperable and reactor steam dome pressure $\geq$ 900 psig, adequate pressure must be supplied to the charging water header. With inadequate charging water pressure, all of the accumulators could become inoperable, resulting in a potentially severe degradation of the scram performance. Therefore, within 1 hour from discovery of charging water header pressure < 940 psig concurrent with Condition B, adequate charging water header pressure must be restored. The allowed Completion Time of 1 hour is reasonable, to place a CRD pump into service to restore the charging water header pressure, if required. This Completion Time is based on the ability of the reactor pressure alone to fully insert all control rods and the need to place the CRD pump into service in a controlled manner. The CRD system provides water to the Reactor Level Instruments Reference Legs Backfill System. Unless properly isolated from the CRD system prior to a CRD pump start, there is the possibility of introducing air into the Reactor Level Instruments Reference Legs Backfill System. Air in the Reactor Level Instruments Reference Legs could cause inadvertent ECCS initiations and PCIS isolations.

The control rod may be declared "slow," since the control rod will still scram using only reactor pressure, but may not satisfy the times in Table 3.1.4-1. Required Action B.2.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control rod scram time is within the limits of Table 3.1.4-1 during the last scram time surveillance. Otherwise, the control rod would already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action B.2.2) and LCO 3.1.3 entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby

(continued)

BASES

ACTIONS

B.1, B.2.1 and B.2.2 (continued)

satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is reasonable, based on the ability of only the reactor pressure to scram the control rods and the low probability of a DBA or transient occurring while the affected accumulators are inoperable.

C.1 and C.2

With one or more control rod scram accumulators inoperable and the reactor steam dome pressure < 900 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor steam dome pressure < 900 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become severely degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 940 psig, concurrent with Condition C, all control rods associated with inoperable accumulators must be verified to be fully inserted. Withdrawn control rods with inoperable accumulators may fail to scram under these low pressure conditions. The associated control rods must also be declared inoperable within 1 hour. The allowed Completion Time of 1 hour is reasonable for Required Action C.2, considering the low probability of a DBA or transient occurring during the time that the accumulator is inoperable.

(continued)

BASES

ACTIONS (continued)

D.1

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with loss of the CRD charging pump (Required Actions B.1 and C.1) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown position is permitted by the definition of an Immediate Completion Time. This Required Action is modified by a Note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the accumulator pressure be checked periodically to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of 1100 psig (Ref. 1). Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 4.3.3.
2. UFSAR, Section 5.2.2 and Appendix 5B.
3. UFSAR, Section 15.0.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the Rod Worth Minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to 10% RTP. The sequences limit the potential amount of reactivity addition that could occur in the event of a Control Rod Drop Accident (CRDA).

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1 and 2.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RWM (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage which could result in the undue release of radioactivity. Since the failure consequences for UO_2 have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 3), the fuel damage limit of 280 cal/gm provides a margin of safety from significant core damage which would result in release of radioactivity (Refs. 4 and 5). Generic evaluations (Refs. 1 and 6) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 7) and the calculated offsite doses will be well within the required limits (Ref. 5).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in Reference 1 follow the Banked Position Withdrawal Sequence (BPWS). The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 2). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are established to minimize the maximum incremental control rod worth without being overly restrictive during normal plant operation. Generic analysis of the BPWS (Ref. 1) has demonstrated that the 280 cal/gm fuel damage limit will not be violated during a CRDA while following the BPWS mode of operation. The generic BPWS analysis (Ref. 8) also evaluates the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods. The Reduced Notch Worth Procedure (RNWP) (Ref. 9) is an extension of the BPWS and may be used at DAEC during control rod withdrawal to avoid high notch worth scrams.

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 10) may be used provided that all withdrawn control rods have been confirmed to be coupled. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled. When using the Reference 10 control rod sequence for shutdown, the Rod Worth Minimizer may be reprogrammed to enforce the requirements of the improved BPWS control rod insertion process, or bypassed in accordance with the allowance provided in the Applicability Note for the Rod Worth Minimizer in Table 3.3.2.1-1.

In order to use the Reference 10 BPWS shutdown process, an extra check is required in order to consider a control rod to be “confirmed” to be coupled. This extra check ensures that no Single Operator Error can result in an incorrect coupling check. For purposes of this shutdown process, the method for confirming that control rods are coupled varies depending on the position of the control rod in the core. Details on this coupling confirmation requirement are provided in site procedures, which conform to Reference 10. If the requirements for use of the BPWS control rod insertion process contained in Reference 10 are followed, the plant is considered to be in compliance with BPWS requirements, as required by LCO 3.1.6

Rod Pattern Control satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, “Control Rod OPERABILITY,” consistent with the allowances for inoperable control rods in the BPWS.

APPLICABILITY

In MODES 1 and 2, when THERMAL POWER is ≤ 10% RTP, the CRDA is a Design Basis Accident and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 10% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 2). In MODES 3, 4, and 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

ACTIONS

A.1 and A.2

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, actions may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of "double notching," drifting from a control rod drive cooling water transient, leaking scram valves, or a power reduction to ≤ 10% RTP before establishing the correct control rod pattern. The number of OPERABLE control rods not in compliance with the prescribed sequence is limited to eight, to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence.

Required Action A.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator or a qualified member of the technical staff (i.e., personnel trained in accordance with an approved training program). This ensures

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

that the control rods will be moved to the correct position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out of sequence control rods and the low probability of a CRDA occurring during the time the control rods are out of sequence.

B.1, and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal must be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than withdrawals have. Required Action B.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator or a qualified member of the technical staff.

When nine or more OPERABLE control rods are not in compliance with BPWS, the reactor mode switch must be placed in the Shutdown position within 1 hour. With the mode switch in Shutdown, the reactor is shut down, and as such, does not meet the applicability requirements of this LCO. The Required Action to place the reactor mode switch in the Shutdown position within 1 hour does not preclude a manual scram from being inserted beforehand. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is periodically verified to be in compliance with the BPWS to ensure the assumptions of the CRDA analyses are met. The Frequency was developed considering that the primary check on compliance with the BPWS is performed by the RWM (LCO 3.3.2.1), which provides control rod blocks to enforce the required sequence and is required to be OPERABLE when operating at $\leq$ 10% RTP. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. NEDE-24011-P-A-US, "General Electric Standard Application for Reactor Fuel, Supplement for United States," Section 2.2.3.1.

2. Letter from T. A. Pickens (BWROG) to G.E. Laines (NRC), "Revision 17 to General Electric Licensing Topical Report NEDE-24011-P-A", BWROG-8644, August 15, 1988.

3. NUREG-0979, Section 4.2.1.3.2, April 1983.

4. NUREG-0800, Section 15.4.9, Revision 2, July 1981.

5. 10 CFR 50.67.

6. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

7. ASME, Boiler and Pressure Vessel Code.

8. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

9. GE SIL No. 316, "Reduced Notch Worth Procedures," November 1979.

10. NEDO-33091-A, Rev.2, “Improved BPWS Control Rod Insertion Process,” July 2004.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement. In addition, the SLC System is relied upon to satisfy the requirements of 10 CFR 50.62 (Ref. 1) on Anticipated Transient Without Scram (ATWS).

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves that are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged near the bottom of the core shroud, where it then mixes with the cooling water rising through the core. A smaller tank containing demineralized water is provided for testing purposes.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that enough control rods cannot be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to add negative reactivity to compensate for all of the various reactivity effects that could occur during plant operations. To meet this objective, it is necessary to inject a quantity of boron, using both SLC pumps, which produces a concentration of 660 ppm of natural boron, in the reactor coolant at 70°F. To compensate for potential leakage and imperfect mixing in the reactor system, an additional amount of boron equal to 25% of the amount cited above is added (Ref. 2). The volume versus concentration limits in Figure 3.1.7-1 and the temperature versus concentration limits in Figure 3.1.7-2 are calculated such that the required concentration is achieved

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount that is above the pump suction shutoff level in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected. The NRC's final rule on Anticipated Transients Without Scram (ATWS), 10 CFR 50.62, requires that the SLC System be modified to provide an equivalent shutdown capability of 86 gpm at 13.4 weight percent natural boron for a 251 inch I.D. vessel. For DAEC, ATWS equivalence is achieved by running both SLC system pumps simultaneously at a minimum combined flow of 45 gpm at a nominal boron concentration of 13% weight percent natural boron, (Ref. 3). The equivalence is also met if both pumps supply their minimum Technical Specification flowrate of 26.2 gpm each with a solution concentration of at least 11.2 weight percent natural boron. Although the SLC pump circuitry has been modified to run both pumps simultaneously in order to comply with the ATWS rule requirements, only one of the two SLC pumps is needed for meeting the original design basis.

The SLC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) because operating experience and probabilistic risk assessments have shown the SLC System to be important to public health and safety. Thus, it is retained in the Technical Specifications.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

ACTIONS

A.1

If one SLC subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the original licensing basis shutdown function. However, the overall capability is reduced since the remaining OPERABLE subsystem cannot meet the requirements of Reference 1. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the original licensing basis SLC System function and the low probability of an event occurring concurrent with the failure of the Control Rod Drive (CRD) System to shut down the plant.

B.1

If both SLC subsystems are inoperable at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of the failure of the control rods to shut down the reactor.

C.1

If any Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 are Surveillances verifying certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure that the proper borated solution volume and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. The temperature versus concentration curve of Figure 3.1.7-2 ensures that a 5°F margin will be maintained above the saturation temperature. The Frequency is based on operating experience and has shown there are relatively slow variations in the measured parameters of volume and temperature. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.4

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure that proper operation will occur if required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Frequency is based on operating experience and has demonstrated the reliability of the explosive charge continuity. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of boron exists in the storage tank. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to determine that the boron solution concentration is within the specified limits. SR 3.1.7.5 must also be performed anytime the temperature is restored to within the limits of Figure 3.1.7-2, to ensure that no significant boron precipitation occurred. The Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances. The Surveillance Frequency is controlled under the Surveillance Frequency Control Progam.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.6

Demonstrating that each SLC System pump develops a flow rate ≥ 26.2 gpm at a discharge pressure ≥ 1150 psig when pumping demineralized water to the test tank ensures that pump performance has not degraded below design values during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.1.7.7 and SR 3.1.7.8

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.7 and SR 3.1.7.8 (continued)

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. Acceptable methods for verifying that the suction piping is unblocked include pumping from the storage tank to the test tank or establishing flow from the pump suction drains.

The periodic Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The periodic Frequency is acceptable since there is a low probability that the subject piping will be blocked due to precipitation of the boron from solution in the heat traced piping. This is especially true in light of the temperature verification of this piping required by SR 3.1.7.3. However, if, in performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum, SR 3.1.7.8 must be performed once within 24 hours after the piping temperature is restored to within the limits of Figure 3.1.7-2.

REFERENCES

1. 10 CFR 50.62.

2. UFSAR, Section 9.3.4.3.

3. NEDC-30859, "Duane Arnold ATWS Assessments" December 1984.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. As discussed in Reference 3, the SDV vent and drain valves need not be considered Primary Containment Isolation Valves (PCIVs) for the Scram Discharge System. The SDV is a volume of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two SDVs (headers) and two instrument volumes, each receiving approximately one half of the control rod drive (CRD) discharges. The two instrument volumes are connected to a common drain line with two valves in series; and each header is connected to a common vent line with two valves in series, for a total of four vent and drain valves. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference 1.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all of the control rods are capable of scramming. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to:

a. Close during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite doses remain within the limits of 10 CFR 50.67 (Ref. 2); and

b. Open on scram reset to maintain the SDV vent and drain path open so that there is sufficient volume to accept the reactor coolant discharged during a scram.

Isolation of the SDV can also be accomplished by manual closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite doses are well within the limits of 10 CFR 50.67 (Ref. 2),

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves allow continuous drainage of the SDV during normal plant operation to ensure that the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level in the instrument volume exceeds a specified setpoint. The setpoint is chosen so that all control rods are inserted before the SDV has insufficient volume to accept a full scram.

SDV Vent and Drain Valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

APPLICABILITY

In MODES 1 and 2, scram may be required; therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. Also, during MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram.

ACTIONS

The ACTIONS Table is modified by Note 1 indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required Actions may

(continued)

BASES

ACTIONS (continued)

allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS Table is modified by a second Note stating that an isolated line may be unisolated under administrative control to allow draining and venting of the SDV. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open.

A.1

When one SDV vent or drain valve is inoperable in one or more lines, the associated line must be isolated to contain the reactor coolant during a scram. The 7 day Completion Time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable and the line is not isolated. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

B.1

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram.

The 8 hour Completion Time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and unlikelihood of significant CRD seal leakage.

(continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. .

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

During normal operation, the SDV vent and drain valves should be in the open position (except when performing SR 3.1.8.2) to allow for drainage of the SDV piping. Verifying that each valve is in the open position ensures that the SDV vent and drain valves will perform their intended functions during normal operation. This SR does not require any testing or valve manipulation; rather, it involves verification that the valves are in the correct position. This SR is modified by a Note that allows the SR to be met for OPERABLE valves that are temporarily closed while performing the testing required by SR 3.1.8.2. The Note is necessary to avoid potential conflicts between the two SRs created by SR 3.0.1.

The Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation, which ensure correct valve positions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.2

During a scram, the SDV vent and drain valves should close to contain the reactor water discharged to the SDV piping. Cycling each valve through its complete range of motion (closed and open) ensures that the valve will function properly during a scram. The Frequency is based on operating experience and takes into account the level of redundancy in the system design as well as being in accordance with the INSERVICE TESTING PROGRAM.

(continued)

BASES

SURVELLANCE REQUIREMENTS (continued)

SR 3.1.8.3

SR 3.1.8.3 is an integrated test of the SDV vent and drain valves to verify total system performance. After receipt of a simulated or actual scram signal, the closure of the SDV vent and drain valves is verified. The closure time of 30 seconds after receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis (Ref. 2). Similarly, after receipt of a simulated or actual scram reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3 overlap this Surveillance to provide complete testing of the assumed safety function. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 4.6.2.3.

2. 10 CFR 50.67.

3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

BASES

BACKGROUND

The APLHGR is a measure of the Linear Heat Generation Rate (LHGR), expressed in kW/ft, of all the fuel rods in a fuel assembly at any axial location. APLHGR has two key components: limits on the APLHGR are specified to ensure that the fuel design limits identified in Reference 1 are not exceeded during Abnormal Operational Transients; and, also to assure that the Peak Cladding Temperature (PCT) during the postulated design basis Loss Of Coolant Accident (LOCA) does not exceed the limits specified in 10 CFR 50.46.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel design limits are presented in References 1 and 2. The analytical methods and assumptions used in evaluating Design Basis Accidents (DBAs), anticipated operational transients, and normal operation that determine the APLHGR limits are presented in References 1, 2, 3, 4 and 5.

Fuel design evaluations are performed to demonstrate that the 1% limit on the fuel cladding plastic strain and other fuel design limits described in Reference 1 are not exceeded during Abnormal Operational Transients for operation with LHGRs up to the operating limit LHGR. The Maximum LHGR (MLHGR) is the highest surface heat flux on the fuel rod at a given nodal plane in the bundle. These limits are developed for each bundle type in the core as a function of exposure and the various operating core flow and power states to ensure adherence to fuel design limits during the limiting Abnormal Operational Transients (Refs. 1, and 5). The actual MLHGR values for the GE fuel design are lattice-type dependent and, with the introduction of advanced modeling capabilities (Ref. 9), are explicitly modeled by the plant process computer. The lattice-type dependent values can be found in Reference 8.

Flow dependent MLHGR limits are determined using the three dimensional BWR simulator code (Ref. 6) to analyze slow flow runout transients. The flow dependent multiplier, $LHGRFAC_f$, is dependent on the maximum core flow runout capability.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum runout flow is dependent on the existing setting of the core flow limiter in the Recirculation System.

Based on analyses of limiting plant transients (other than core flow increases) over a range of power and flow conditions, power dependent multipliers, $LHGRFAC_p$, are also generated. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram trips are bypassed (approximately 26% RTP), both high and low core flow $LHGRFAC_p$ limits are provided for operation at power levels between 21.7% RTP and the previously mentioned bypass power level (26% RTP). The exposure dependent MLHGR limits are reduced by $LHGRFAC_p$ and $LHGRFAC_f$ at various operating conditions to ensure that all fuel design criteria are met for normal operation and Abnormal Operational Transients (Ref. 5). A complete discussion of the analysis code is provided in Reference 7.

LOCA analyses are then performed to ensure that the Maximum Average Planar LHGR (MAPLHGR) limits for the individual fuel type are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis is provided in Reference 3. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. The MAPLHGR limits specified in the COLR are equivalent to the LHGR of the highest powered fuel rod assumed in the LOCA analysis divided by its local peaking factor. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the MAPLHGR.

For single recirculation loop operation, a multiplier is applied to both the MAPLHGR and LHGR limits due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA (Ref. 5). For operation at off-rated conditions, power- and flow-dependent multipliers, $MAPFAC_p$ and $MAPFAC_f$ are applied to the MAPLHGR limits to ensure that the rated power/flow MAPLHGR limits

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

are bounding for operation throughout the allowable operating domain.

The APLHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The APLHGR limits specified in the COLR are the result of the fuel design, DBA, and transient analyses. For two recirculation loops operating, the APLHGR limit for each fuel type is determined by the more-limiting value of either: the smaller of the $LHGRFAC_p$ and $LHGRFAC_f$ factors times the exposure-dependent MLHGR limits or, the smaller of the $MAPFAC_p$ and $MAPFAC_f$ factors times the exposure-dependent MAPLHGR value. With only one recirculation loop in operation, in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating", the APLGHR limit for each fuel type is determined by the more-limiting value of either: the exposure dependent MLHGR limit times the smaller of either $LHGRFAC_p$ or $LHGRFAC_f$, or, a specific single recirculation loop multiplier, found in the COLR, times the exposure-dependent MAPLHGR value or, the smaller of either $MAPFAC_p$ or $MAPFAC_f$ times the exposure dependent MAPLHGR value (Ref. 5).

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA and transient analyses that are assumed to occur at high power levels. Design calculations (Ref. 1) and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor scram function, in addition to the average power range monitor scram in Startup, provides prompt scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels $\leq$ 21.7% RTP, the reactor is operating with substantial margin to the APLHGR limits; thus, this LCO is not required.

(continued)

BASES (continued)

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action should be taken to restore the APLHGR(s) to within the required limits such that the plant operates within analyzed conditions and within design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the APLHGR out of specification.

B.1

If the APLHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 21.7% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 21.7% RTP in an orderly manner and without challenging plant systems because in general, a power reduction from full power would normally have already been initiated as part of Required Action A.1.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is $\geq$ 21.7% RTP and then periodically thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER $\geq$ 21.7% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

(continued)

BASES (continued)

REFERENCES

1. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (latest approved version).

2. UFSAR, Section 15.0.

3. UFSAR, Section 15.2.1.

4. NEDC-32980P, "Safety Analysis Report for Duane Arnold Energy Center Extended Power Uprate," Rev. 1, April 2001.

5. "Supplemental Reload Licensing Report for Duane Arnold Energy Center," (latest version referenced in COLR).

6. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

7. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

8. NEDE-31152P, “GE Fuel Bundle Designs”, (latest version referenced in COLR).

9. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Rev. 14 , June 2000.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of transition boiling to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid transition boiling if the limit is not violated (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during Abnormal Operational Transients. Although fuel damage does not necessarily occur if a fuel rod actually experienced transition boiling (Ref. 1), the critical power at which transition boiling is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the Abnormal Operational Transients to establish the operating limit MCPR are presented in References 2, 3, 4, and 5. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in Critical Power Ratio (CPR). The types of transients evaluated are loss of flow, increase in either reactor pressure or power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR).

The minimum Operating Limit MCPR bounds the sum of the Safety Limit MCPR and the largest ΔCPR. Values for the Operating Limit MCPR are contained in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The required MCPRs at rated power are determined using the GEMINI transient analysis methods described in Reference 2. These limits (ODYN Option A) were derived by using the GE 67B scram times, given in ITS 3.1, which are based upon extensive operating plant data, as well as GE test data. The ODYN Option B scram insertion times were statistically derived from the 67B data to ensure that the resulting Operating Limit from the transient analysis would, with 95% probability at the 95% confidence level, result in the Safety Limit MCPR not being exceeded. The scram time parameter τ is a measure of the conformance of the actual plant control rod drive performance to that used in the ODYN Option B licensing basis.

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 5). The $MCPR_F$s were calculated such that, for the maximum core flow rate and core thermal power along a conservative load line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit MCPR. Using this relative bundle power, the MCPRs were calculated at different points along this conservative load line corresponding to different core flows. Flow dependent MCPR limits are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 6) to analyze slow flow runout transients. At less than 100% of rated power and/or flow, the required Operating Limit MCPR is the larger value of the flow-dependent MCPR ($MCPR_F$) or the power-dependent multiplier (K_P) times the rated power MCPR at the existing core power/flow state. The required Operating Limit MCPR is a function of flow in order to protect the fuel from inadvertent core flow increases such that the Safety Limit MCPR requirement can be assured. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation System. The resulting $MCPR_F$s are given in the COLR.

Power dependent MCPR limits ($MCPR_p$) are determined mainly by the one dimensional transient code (Ref. 7). This limit protects the fuel from Abnormal Operational Transients, including localized events, such as a rod withdrawal error, other than those resulting from inadvertent core flow increases, which are covered by the flow-dependent MCPR limits. This power-dependent MCPR limit was developed based upon bounding analyses for the most

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

was developed based upon bounding analyses for the most limiting transient at the given core power level. Further information on the MCPR operating limits for off-rated conditions is presented in Reference 5 and the COLR. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed (approximately 26% RTP), high and low flow $MCPR_p$ operating limits are provided for operating between 21.7% RTP and the previously mentioned bypass power level (26% RTP).

During SLO, the Operating Limit MCPR must be increased to account for the increased uncertainties used in the statistical analyses to derive the Safety Limit MCPR (see Reference 5 and the COLR).

The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 21.7% RTP, the reactor is operating at a minimum recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 21.7% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs. Statistical analyses indicate that the nominal value of the initial MCPR expected at 21.7% RTP is > 3.5. Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 21.7% RTP. This trend is expected to continue to the 5% to 15% power range when

(continued)

BASES

APPLICABILITY (continued)

entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 21.7% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 21.7% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 21.7% RTP in an orderly manner and without challenging plant systems because in general, a power reduction from full power would normally have already been initiated as part of Required Action A.1.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is $\geq$ 21.7% RTP and then periodically thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER $\geq$ 21.7% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. Therefore, in order to perform SR 3.2.2.2, the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution must first be determined. The MCPR operating limit is then determined based on an interpolation between the applicable limits for Option A (scram times of LCO 3.1.4,"Control Rod Scram Times") and Option B (realistic scram times) analyses. The parameter τ must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1 and SR 3.1.4.2 because the effective scram speed distribution may change after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the large inherent margin to operating limits at low power.

REFERENCES

1. NUREG-0562, June 1979.

2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved version).

3. UFSAR, Chapters 4.2.3, 4.4.2, and 4.4.4.

4. UFSAR, Chapter 15.0.

5. “Supplemental Reload Licensing Report for Duane Arnold Energy Center,” (latest version referenced in COLR).

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BASES

REFERENCES (continued)

6. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

7. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limits, to preserve the integrity of the fuel cladding and the Reactor Coolant Pressure Boundary (RCPB), minimize the energy that must be absorbed following a Loss of Coolant Accident (LOCA), and prevent inadvertent criticality. This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying Limiting Safety System Settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance. The LSSS are defined in this Specification as the Allowable Values, which, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits, including Safety Limits (SLs) during Design Basis Accidents (DBAs) (Ref. 11).

The RPS, as shown in the UFSAR, Figure 7.2-2 (Ref. 1), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a reactor scram. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level, reactor vessel pressure, neutron flux, main steam line isolation valve position, Turbine Control Valve (TCV) fast closure, Electro Hydraulic Control (EHC) trip oil pressure, Turbine Stop Valve (TSV) position, drywell pressure, and Scram Discharge Volume (SDV) water level, as well as reactor mode switch in shutdown position and manual scram signals. There are at least four redundant sensor input signals from each of these parameters (with the exception of the reactor mode switch in shutdown scram signal and the Manual Scram signal, which have only two input signals). Most channels include on-off sensors, bi-stable trip circuits, or trip units that compare measured input signals with pre-established setpoints. When the setpoint is exceeded, the sensor/bi-stable/trip unit

(continued)

BASES

BACKGROUND (continued)

acutates the channel output relay, which then outputs an RPS trip signal to the trip logic.

The RPS is comprised of two independent trip systems (A and B) with three logic channels in each trip system (automatic logic channels A1 and A2, B1 and B2, and manual logic channels A3 and B3) as shown in Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so that either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as a one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed; however, this time delay is not a safety-related function.

Two scram pilot valves are located in the hydraulic control unit for each Control Rod Drive (CRD). Each scram pilot valve is solenoid operated, with the solenoids normally energized. The scram pilot valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either scram pilot valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the scram pilot valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 5, 6, and 7. The RPS initiates a reactor scram prior to when monitored parameter values exceed the Allowable Values, specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the RCPB, and the containment by minimizing the energy that must be absorbed following a LOCA.

RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where specified.

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip Setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor, bi-stable trip circuit, or trip unit) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The Trip Setpoints derived instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The OPERABILITY of scram pilot valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES or other specified conditions specified in the table, which may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions are required in each MODE to provide primary and diverse initiation signals.

The RPS is required to be OPERABLE in MODES 1 and 2 and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and, therefore, are not required to have the capability to scram. Provided all other control rods remain inserted, the RPS function is not required. In this condition, the required SDM (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS will occur. During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. Under these conditions, the RPS function is not required to be OPERABLE.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

Intermediate Range Monitor (IRM)

1.a. Intermediate Range Monitor Neutron Flux — High

The IRMs monitor neutron flux levels from the upper range of the Source Range Monitor (SRM) to the lower range of the Average Power Range Monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from Abnormal Operational Transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection for the Rod Worth Minimizer (RWM), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 2). While no direct credit is taken in the accident analysis for this function, the IRM does provide mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, generic analyses have been performed (Ref. 3) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel energy depositions below the 170 cal/gm fuel failure threshold criterion.

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed.

The IRM System is divided into two groups of IRM channels, with three IRM channels inputting to each trip system. The analysis of Reference 3 assumes that one channel in each trip system is bypassed. Therefore, four channels with two channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The analysis of Reference 3 has adequate conservatism to permit an IRM Allowable Value of 125 divisions of a 125 division scale.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1.a. Intermediate Range Monitor Neutron Flux — High (continued)

The Intermediate Range Monitor Neutron Flux — High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System and the RWM provide protection against control rod withdrawal error events and the IRMs are not required. The IRM trips are automatically bypassed when the reactor mode switch is placed in RUN.

1.b. Intermediate Range Monitor — Inop

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or when a module is not plugged in, an inoperative trip signal will be received by the RPS unless the IRM is bypassed. Since only one IRM in each trip system may be bypassed, only one IRM in each RPS trip system may be inoperable without resulting in an RPS trip signal.

This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

Four channels of Intermediate Range Monitor — Inop with two channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

Since this Function is not assumed in the safety analysis, there is no Allowable Value for this Function.

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux — High Function is required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

Average Power Range Monitor

2.a. Average Power Range Monitor Neutron Flux — Upscale, Startup

The APRM channels receive input signals from the Local Power Range Monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to 125% of RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux — Upscale, Startup Function is capable of generating a trip signal that prevents fuel damage resulting from Abnormal Operational Transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux — Upscale, Startup Function will, in reality, provide a secondary scram to the Intermediate Range Monitor Neutron Flux - High Function because of their relative setpoints. However, with the IRMs on Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux — Upscale, Startup Function will provide the primary trip signal for a corewide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux — Upscale, Startup Function (the Control Rod Drop Accident (CRDA) analysis conservatively assumes the Average Power Range Monitor High Valve clamp provides this trip to mitigate the CRDA). However, this Function indirectly ensures that before the reactor mode switch is placed in the Run position, reactor power does not exceed 21.7% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 21.7% RTP.

The APRM System is divided into two groups of channels with three APRM channel inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux — Upscale, Startup with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux — Upscale, Startup (continued)

coverage of the entire core, at least 9 LPRM inputs for APRM channels A, B, C, and D, and 13 LPRM inputs for APRM channels E and F are required. In addition, at least two LPRM inputs from each of the four axial levels at which the LPRMs are located are required for each APRM channel.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 21.7% RTP.

The Average Power Range Monitor Neutron Flux — Upscale, Startup Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists.

Other than when required by the Shutdown Margin Test - Refueling LCO (LCO 3.10.8), the Average Power Range Monitor Neutron Flux - Upscale, Startup Function need not be OPERABLE in MODE 5, as adequate protection against neutron flux excursions is maintained by the Refueling Interlocks and IRMs.

In MODE 1, the Average Power Range Monitor High Value Clamp Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

2.b. Average Power Range Monitor Flow Biased-High

The Average Power Range Monitor Flow Biased — High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern). The Average Power Range Monitor Flow Biased — High Function provides protection for transients that could be initiated from low power/flow conditions (e.g., recirculation fast flow runup.) The Average Power Range Monitor Flow Based — High Function also provides protection against transients at lower power and core flow levels where the possibility of thermal-hydraulic instabilities exist (e.g., dual recirculation pump trip).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased-High (continued)

If a thermal-hydraulic instability occurs, the Average Power Range Monitor Flow Biased-High Function will initiate a scram before the Average Power Range Monitor-High Value Clamp, thus protecting the fuel cladding integrity by ensuring that the MCPR Safety Limit is not exceeded (Ref. 12).

The APRM System is divided into two groups of channels with three APRM inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Flow Biased — High with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 9 LPRM inputs for APRM channels A, B, C, and D, and 13 LPRM inputs for APRM channels E and F are required. In addition, at least two LPRM inputs from each of the four axial levels at which the LPRMs are located are required for each APRM channel. Each APRM channel receives two total drive flow signals representative of total core flow. The total drive flow signals are generated by four flow units, two of which supply signals to the trip system A APRMs, while the other two supply signals to the trip system B APRMs. Each flow unit signal is provided by summing up the flow signals from the two recirculation loops. To obtain the most conservative reference signals, the total flow signals from the two flow units (associated with a trip system as described above) are routed to a low auction circuit associated with each APRM. Each APRM's auction circuit selects the lower of the two flow unit signals for use as the scram trip reference for that particular APRM. Each required Average Power Range Monitor Flow Biased — High channel only requires an input from one OPERABLE flow unit, since the individual APRM channel will perform the intended function with only one OPERABLE flow unit input. However, in order to maintain single failure criteria for the Function, at least one required Average Power Range Monitor Flow Biased — High channel in each trip system must be capable of maintaining an

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased-High (continued)

OPERABLE flow unit signal in the event of a failure of an auction circuit, or a flow unit, in the associated trip system. The flow units are assigned to bypass switches in the same manner as they are distributed in the APRM System. The bypass switch arrangement prevents the bypassing of more than one flow unit supplying signals to the Rod Block circuitry. If a flow unit is inoperable, it may be bypassed; however, the bypass function does not remove the flow unit's output to the APRM circuit. When a flow unit is placed in a position other than "operate" or "standby", its output to the low auction circuit will be maximum, making the low auction circuit select the input from the operating flow unit. If both flow units associated with an APRM channel are in positions other than "operate" or "standby", that APRM channel shall be considered inoperable.

The Allowable Values (AVs) are calculated from the Analytic Limit (AL) straight line equations for two-loop operation (TLO) and single-loop operation (SLO). These ALs are derived from the safety analyses that take credit for the Average Power Range Monitor Flow Biased-High Function as part of the implementation of the Maximum Extended Load Line Limit Analysis (MELLLA). The AVs and setpoints are in accordance with an NRC-approved Setpoint Methodology. The flow biased AVs and setpoints vary linearly with drive flow. They have the same slope versus drive flow as the ALs, but have different (i.e. lower) intercepts on the drive flow equal to zero axis.

Resetting of APRM Flow Biased Scram Setpoint High for single recirculation loop operation (SLO) may be accomplished by either adjusting the APRM gain such that indicated power is higher than actual by the difference between the TLO and SLO setpoints (i.e. 6.3%), or by recalibrating the APRMs to the lower SLO setpoint. Adjusting the gain is a simple procedure where the APRM output is adjusted to indicate core power plus the difference between the TLO and SLO setpoints. Full recalibration to change the actual trip setpoint is more complicated and time consuming. Adjusting the gain can be accomplished in a matter of minutes but requires readjusting the gain whenever core power is changed. The full recalibration method also requires a second recalibration to restore the original setpoint when the plant re-enters two recirculation loop operation. For these reasons, when the plant

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased-High (continued)

enters SLO, the APRM gain is initially adjusted to lower the setpoints as required by LCO 3.4.1, “Recirculation Loops Operating.” Continued adjustment of APRM gains is acceptable if it is expected that the plant will operate in SLO for a limited period of time. If the plant is expected to be in SLO for an extended period of time, the APRM setpoints should be fully recalibrated to eliminate the need to adjust APRM gain whenever power is changed.

The Average Power Range Monitor Flow Biased — High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor High Value Clamp

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor High Value Clamp Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure and is credited in the DAEC accident and transient analyses for mitigating these events. In particular, the overpressurization protection analysis of Reference 4, the Average Power Range Monitor High Value Clamp Function is assumed to terminate the Main Steam Isolation Valve (MSIV) closure event and, along with the Safety Relief Valves (SRVs), limits the peak Reactor Pressure Vessel (RPV) pressure to less than the ASME Code limits. The Control Rod Drop Accident (CRDA) analysis (Ref. 5) takes credit for the Average Power Range Monitor High Value Clamp Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor High Value Clamp with two channels in each

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Average Power Range Monitor High Value Clamp (continued)

trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 9 LPRM inputs for APRM channels A, B, C, and D, and 13 LPRM inputs for APRM channels E and F are required. In addition, at least two LPRM inputs from each of the four axial levels at which the LPRMs are located are required for each APRM channel.

The Allowable Value is based on the Analytical Limit assumed in the analysis of Abnormal Operational Transients.

The Average Power Range Monitor High Value Clamp Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor High Value Clamp Function is assumed in the CRDA analysis, which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux — Upscale, Startup Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor High Value Clamp Function is not required in MODE 2.

2.d. Average Power Range Monitor — Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, the electronic operating voltage is low, or the APRM has too few LPRM inputs (< 9 for APRM Channels A, B, C, and D, and < 13 for APRM channels E and F), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor — Inop (continued)

Four channels of Average Power Range Monitor — Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure — High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure — High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 4, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor High Value Clamp signal, not the Reactor Vessel Steam Dome Pressure — High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters/alarm units that sense reactor pressure. The Reactor Vessel Steam Dome Pressure — High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure — High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

3. Reactor Vessel Steam Dome Pressure — High (continued)

Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level — Low

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at the single low reactor vessel water level to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level — Low Function is assumed in the analysis of the Design Basis Accident (DBA-LOCA) (Ref. 6). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level — Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level — Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level — Low Allowable Value is selected to ensure that: 1) during normal operation the separator skirts are not uncovered (this protects available recirculation pump Net Positive Suction Head (NPSH) from significant carryunder); 2) during abnormal operating transients the value selected ensures that the fission process is terminated to protect the fuel from overheating (Safety Limit Minimum Critical Power Ratio – SLMCPR); and 3) as noted above, the value also is critical to protecting the fuel from overheating during a DBA-LOCA. The DBA response is the most critical of these for setting the Allowable Value.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Reactor Vessel Water Level — Low (continued)

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor Vessel Water Level — Low Low and Low Low Low provide sufficient protection for level transients in all other MODES.

5. Main Steam Isolation Valve — Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve — Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 4, the Average Power Range Monitor High Value Clamp Function, along with the SRVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in Reference 7 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow).

The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. Each MSIV has one position switch that provides an input to both the RPS A and B trip systems. There are a total of eight MSIV closure channels, with four channels in each trip system. Each channel receives input from an inboard MSIV and an outboard MSIV. The logic for the Main Steam Isolation Valve — Closure Function is arranged such that either the inboard or outboard valve on two main steam lines closing may produce a half scram, while the closing of either the inboard or outboard valves on three or more of the main steam lines will always produce a full scram.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Main Steam Isolation Valve — Closure (continued)

The Main Steam Isolation Valve — Closure Allowable Value is specified to ensure that a scram occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

Eight channels of the Main Steam Isolation Valve — Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 since, with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close. Therefore, this Function is automatically bypassed when the reactor mode switch is not in the Run position. In MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

6. Drywell Pressure — High

High pressure in the drywell could indicate a break in the RCPB. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the drywell. The Drywell Pressure — High Function is a secondary scram signal to Reactor Vessel Water Level — Low for LOCA events inside the drywell, and credit is taken for a scram initiated from this Function in the analysis of the containment response to a LOCA. This Function is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

High drywell pressure signals are initiated from four pressure transmitters that sense drywell pressure. The Allowable Value was selected to ensure that the primary containment design pressure is not exceeded upon the occurrence of a DBA LOCA inside primary containment, while the nominal trip setpoint is selected to avoid spurious trips due to non-LOCA events.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Drywell Pressure — High (continued)

Four channels of Drywell Pressure — High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

7a. 7b. Scram Discharge Volume Water Level - High

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated while the remaining free volume is still sufficient to accommodate the water from a full core scram. The two types of Scram Discharge Volume Water Level — High Functions are an input to the RPS logic. No credit is taken for a scram initiated from these Functions for any of the design basis accidents or transients analyzed in the UFSAR. However, they are retained to ensure the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two thermal probes for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a thermal probe to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 8.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level — High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7a. 7b. Scram Discharge Volume Water Level – High (continued)

cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve-Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve — Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 7. This Function also actuates the End of Cycle Recirculation Pump Trip (EOC-RPT) System. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System (or appropriate MCPR penalty with the EOC-RPT System inoperable), ensures that the MCPR SL is not exceeded.

Turbine Stop Valve — Closure signals are initiated from position switches located on each of the four TSVs. Two independent position switches are associated with each stop valve. One of the two switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve — Closure channels, each consisting of one position switch. The logic for the Turbine Stop Valve — Closure Function is such that two TSVs closing may produce a half scram, while the closing of three or more TSVs will always produce a full scram. This Function must be enabled whenever THERMAL POWER $\geq$ 26% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this Function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed in order to maintain this Function OPERABLE whenever THERMAL POWER is $\geq$ 26%.

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Turbine Stop Valve-Closure (continued)

In addition, other steam loads, such as second stage reheaters in operation below 26% RTP, must be accounted for in establishing this setpoint. Otherwise, turbine first stage pressure would be non-conservative with respect to the 26% RTP RPS bypass. The Turbine Stop Valve — Closure Allowable Value is selected to be high enough to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve — Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is $\geq$ 26% RTP. This Function is not required when THERMAL POWER is < 26% RTP since the Reactor Vessel Steam Dome Pressure — High and the Average Power Range Monitor High Value Clamp Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Trip Oil Pressure — Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 7. This Function also actuates the EOC-RPT System. The generator load rejection event analysis actually uses a response time for the TCV fast closure (i.e., from event initiation to the start of the TCV closure $\leq$ 30 msec). The setting for the pressure switch corresponds to the response time. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System (or appropriate MCPR penalty with the EOC-RPT System inoperable) ensures that the MCPR SL is not exceeded.

(continued)

BASES

APPPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low (continued)

Turbine Control Valve Fast Closure, Trip Oil Pressure — Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each control valve. One pressure transmitter is associated with each control valve, and the signal from each transmitter is assigned to a separate RPS logic channel. This Function must be enable whenever THERMAL POWER ≥ 26% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this Function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed in order to maintain this Function OPERABLE when THERMAL POWER is ≥ 26% RTP. In addition, other steam loads, such as second stage reheaters in operation below 26% RTP, must be accounted for in establishing this setpoint. Otherwise, turbine first stage pressure would be non-conservative with respect to the 26% RTP RPS bypass.

The Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Allowable Value is selected high enough to detect imminent TCV fast closure and corresponds to the response time (≤ 30 msec) used in the transient analysis.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ 26% RTP. This Function is not required when THERMAL POWER is < 26% RTP, since the Reactor Vessel Steam Dome Pressure — High and the Average Power Range Monitor High Value Clamp Functions are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

10. Reactor Mode Switch — Shutdown Position

The Reactor Mode Switch — Shutdown Position Function provides signals, via the manual scram logic channels, to the scram valve pilot solenoids. The manual scram logic channels (A3 and B3) are separate from the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with two channels, each of which provides input into one of the RPS manual scram logic channels.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

Two channels of Reactor Mode Switch — Shutdown Position Function, with one channel in each trip system, are available and required to be OPERABLE. The Reactor Mode Switch — Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

11. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, to the scram valve pilot solenoids. The manual scram logic channels (A3 and B3) are separate from the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the manual scram logic channels. In order to cause a scram it is necessary that the one channel in each trip system be actuated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

11. Manual Scram (continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of Manual Scram with one channel in each trip system are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

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 (Ref. 9) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 9 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 9, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, isolation, or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram, isolation, or RPT), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve — Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve — Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS (continued)

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, and G.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 9) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1 (continued)

during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.4.1, "Recirculation Loops Operating," allows the APRMs to be reading greater than actual THERMAL POWER to effectively lower the APRM Flow Biased High setpoints by 6.3% for single recirculation loop operation. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated power plus 6.3%. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when < 21.7% RTP is provided that requires the SR to be met only at $\geq$ 21.7% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 21.7% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At $\geq$ 21.7% RTP, the Surveillance is required to have been satisfactorily performed within the previous Frequency, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 21.7% if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 21.7% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

There are four pairs of RPS automatic scram contactors (i.e., K14 relay contacts) with each pair associated with an automatic scram logic (A1, A2, B1, and B2). The automatic scram contactors can be functionally tested without the necessity of using an automatic scram

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.3 (continued)

function trip. This functional test can be accomplished by placing the associated RPS Test Switch in the trip position, which will deenergize a pair of the automatic scram contactors and in turn, trip the associated RPS logic. The RPS Test Switches were not specifically credited in the accident analysis and thus, do not have any OPERABILITY requirements of their own. However, because the Manual Scram pushbuttons at the DAEC are not configured the same as the generic model (i.e., they are in a separate RPS logic - A3 and B3), the RPS Test Switches have been found to be functionally equivalent to the Manual Scram pushbuttons in the generic model for performing the functional test of the automatic scram contactors. If an RPS Test Switch(es) is (are) not available for performing this test, it is permissible to take credit for a CHANNEL FUNCTIONAL TEST of an automatic RPS trip function (i.e., SR 3.3.1.1.9), if performed within the required Frequency for this Surveillance, as it will also test the K14 relay contacts.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.4 (continued)

This allows entry into MODE 2 if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 9).

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis using the concepts developed in Reference 10.

SR 3.3.1.1.6 and SR 3.3.1.1.7

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a neutron flux region without adequate indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block (i.e., approximately one-half decade of range). Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are indicating at least 5/40 on range 1 before SRMs have reached 10^6 counts per second.

As noted, SR 3.3.1.1.7 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined using analytical methods with input from the axial flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.13

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.9 and SR 3.3.1.1.13 (continued)

are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency of SR 3.3.1.1.13 is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

SR 3.3.1.1.10

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.11, SR 3.3.1.1.12 and SR 3.3.1.1.14

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. The CHANNEL CALIBRATION for Functions 5 and 8 shall consist of the physical inspection and actuation of these position switches.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.11, SR 3.3.1.1.12 and SR 3.3.1.1.14 (continued)

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the calorimetric calibration (SR 3.3.1.1.2) and the LPRM calibration against the TIPs (SR 3.3.1.1.8). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the assumption of a specified calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve — Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 26% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow, as well as other turbine steam loads, can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 26% RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 26% RTP, either due to open main turbine bypass valve(s) (e.g., required testing or upon actual demand) or other reasons, such as changes in turbine steamload to the Main Steam Reheaters), then the affected Turbine Stop Valve — Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

The Average Power Range Monitor Flow Biased — High Function uses the recirculation loop drive flows to vary the trip setpoint. This SR ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a calibrated flow signal and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. Each flow signal from the respective flow unit must be ≤ 110% of the calibrated flow signal. If the flow unit signal is not within the limit, that flow unit may be bypassed, and its output to the low auction circuit will be maximum, making the low auction circuit select the input from the operating flow unit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.17 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, operating experience, the reliability of this instrumentation, the other surveillances performed on the components of the flow biasing network, and the fact that a half scram will be present for an extended period of time during the performance of this surveillance.

SR 3.3.1.1.18

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS Response Time test only applies to the Functions of Reactor Vessel Water Level - Low and Reactor Vessel Steam Dome Pressure - High. These RPS Functions are the only ones that were identified, in a program conducted prior to the first refueling outage, that require sensor response time testing. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 13.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.1.1.19

This SR ensures that the RPS logic system response times are less than or equal to the maximum value assumed in the accident analysis. The RPS logic system response time test is measured from the opening of the sensor contact up to and including the opening of the trip actuator contacts. As such, this test does not include the sensor response time. All RPS Functions except the RPS Manual Scram and Reactor Mode Switch - Shutdown Position are included in this test.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.19 (continued)

These two RPS Functions are excluded since they directly trip their scram solenoid relays without any intervening devices, thus there is nothing to response time test. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS logic system response time acceptance criteria are included in Reference 13. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

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3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
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10. Reliability of Engineered Safety Features as a Function of Testing Frequency, Volume 9, No. 4, July-August 1968.

(continued)

BASES

REFERENCES (continued)

11. DBD-A61-005, Setpoints and Margins Topical Design Bases Document

12. UFSAR, Section 15.3.4.2.

13. UFSAR 7.2.1.3.

B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to Intermediate Range Monitor (IRM) overlap is demonstrated (as required by SR 3.3.1.1.6), the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels. Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors (i.e., "dunking chambers") connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation is provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"; IRM Neutron Flux — High and Average Power Range Monitor (APRM) Neutron Flux — Upscale, Startup Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

.(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SRMs have no safety function and are not assumed to function during any UFSAR design basis accident or transient analysis. However, the SRMs provide the only on-scale monitoring of neutron flux levels during startup and refueling. Therefore, they are retained in Technical Specifications.

LCO

During startup in MODE 2, three of the four SRM channels are required to be OPERABLE to monitor the reactor flux level prior to and during control rod withdrawal, subcritical multiplication and reactor criticality, and neutron flux level and reactor period until the flux level is sufficient to maintain the IRM on Range 3 or above. All but one of the channels are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core.

In MODES 3 and 4, with the reactor shut down, two SRM channels provide redundant monitoring of flux levels in the core.

In MODE 5, during a spiral offload or reload, an SRM outside the fueled region is not required to be OPERABLE, since it is not capable of monitoring neutron flux in the fueled region of the core. Thus, CORE ALTERATIONS are allowed in a quadrant with no OPERABLE SRM in an adjacent quadrant provided the Table 3.3.1.2-1, footnote (b), requirement that the bundles being spiral reloaded or spiral offloaded are all in a single fueled region containing at least one OPERABLE SRM is met. Spiral reloading and offloading encompass reloading or offloading a cell on the edge of a continuous fueled region (the cell can be reloaded or offloaded in any sequence).

In nonspiral routine operations, two SRMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate coverage is provided by requiring one SRM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed, and the other SRM to be OPERABLE in an adjacent quadrant containing fuel. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS.

.(continued)

BASES

LCO (continued)

Special movable detectors, according to footnote (c) of Table 3.3.1.2-1, may be used in place of the normal SRM nuclear detectors. These special detectors must be connected to the normal SRM circuits in the NMS, such that the applicable neutron flux indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2 and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.

APPLICABILITY

The SRMs are required to be OPERABLE in MODE 2 (prior to the IRMs being on scale on Range 3), and MODES 3, 4, and 5 to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor neutron flux is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Provided at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This time is reasonable because there is adequate capability remaining to monitor the core, there is limited risk of an event during this time, and there is sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish flux monitoring capability by the IRMs. During this time, control rod withdrawal and power increase is not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap required by SR 3.3.1.1.6), and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2 below IRM Range 3, if the required number of SRMs are not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or more required SRMs inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRMs occurring during this interval.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the ability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Action (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each SRM Applicable MODE or other specified conditions are found in the SRs column of Table 3.3.1.2-1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.1 and SR 3.3.1.2.3

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on another channel. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience that demonstrates channel failure is rare. While in MODES 3 and 4, reactivity changes are not expected; therefore, the Frequency is relaxed from MODES 2 and 5. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core when the fueled region encompasses more than one SRM, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that the SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE, per Table 3.3.1.2-1, footnote (b),

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.2 (continued)

only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience and supplements operational controls over refueling activities that include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate with the detector fully inserted into the core. The requirement of at least 3 cps assures that any transient, should it occur, begins at or above the initial value of 10^{-8} of RTP which is used in the analysis of transients in cold conditions. With few fuel assemblies loaded, the SRMs may not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met on an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated core quadrant, even with a control rod withdrawn, the configuration will not be critical.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon channel redundancy and other information available in the control room, and ensures that the required channels are frequently monitored during CORE ALTERATIONS. When no reactivity changes are in progress, the Frequency is relaxed from that during CORE ALTERATIONS.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.
SR 3.3.1.2.5 is required in MODE 5, and the Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience and on other Surveillances (such as a CHANNEL CHECK), that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

SR 3.3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below, and in MODES 3 and 4. Since core reactivity changes do not normally take place in MODES 3 and 4 and core reactivity changes are due solely to control rod movement in MODE 2, the Frequency has been extended from that in MODE 5. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

The Note to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability (THERMAL POWER decreased to IRM Range 2 or below). The SR must be performed within 12 hours after IRMs are on Range 2 or below. The allowance to enter the Applicability with the Surveillance Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM detectors and associated circuitry. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. Note 1 to the Surveillance allows the neutron detectors to be excluded from the CHANNEL CALIBRATION because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life.

Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the Surveillance Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, logic circuitry, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the Rod Block Monitor (RBM) provides protection for control rod withdrawal error events. During low power operations, control rod blocks from the Rod Worth Minimizer (RWM) enforce specific control rod sequences designed to mitigate the consequences of the Control Rod Drop Accident (CRDA). During shutdown conditions, control rod blocks from the Reactor Mode Switch — Shutdown Position Function ensure that all control rods remain inserted to prevent inadvertent criticalities.

The purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations. It is assumed to function to block further control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RBM supplies a trip signal to the Reactor Manual Control System (RMCS) to appropriately inhibit control rod withdrawal during power operation above the low power range setpoint. The RBM has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. One RBM channel inputs into one RMCS rod block circuit and the other RBM channel inputs into the second RMCS rod block circuit. The RBM channel signal is generated by averaging a set of Local Power Range Monitor (LPRM) signals at various core heights surrounding the control rod being withdrawn. A signal from one Average Power Range Monitor (APRM) channel assigned to each Reactor Protection System (RPS) trip system supplies a reference signal for the RBM channel in the same trip system. This reference signal is used to determine which RBM range setpoint (low, intermediate, or high) is enabled. If the APRM is indicating less than the low power range setpoint, the RBM is automatically bypassed. The RBM is also automatically bypassed if a peripheral control rod is selected (Ref. 1).

(continued)

BASES

BACKGROUND (continued)

The purpose of the RWM is to control rod patterns during startup and shutdown, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. Prescribed control rod sequences are stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based on position indication for each control rod. The RWM also uses feedwater flow and steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). However, the RWM has been physically modified at the DAEC so that it controls rod patterns over the entire operating range, up to 100% RTP (i.e., it is not automatically bypassed above a preset power level). The RWM is a single channel system that provides input into both RMCS rod block circuits.

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents inadvertent criticality as the result of a control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, each inputting into a separate RMCS rod block circuit. A rod block in either RMCS circuit will provide a control rod block to all control rods.

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control Rod Withdrawal Error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 3. A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event. From these responses, the fuel thermal performance as a function of RBM Allowable Value was determined. The Allowable Values are chosen as a function of power level. Based on the specified Allowable Values, operating limits are established.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

The RBM Function satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

Two channels of the RBM are required to be OPERABLE, with their setpoints within the appropriate Allowable Value for the associated power range, to ensure that no single instrument failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with the DAEC Instrument Setpoint Methodology. The RBM Downscale Function is not required to have a specified Allowable Value setpoint, since this Function does not affect the Rod Withdrawal Error analysis (Ref. 3).

Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., pressure switch) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The RBM is assumed to mitigate the consequences of a RWE event when operating $\geq$ 30% RTP. Below this power level, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

(Ref. 3). When operating < 90% RTP, analyses (Ref. 3) have shown that with an initial MCPR greater than or equal to the limit specified in the COLR, no RWE event will result in exceeding the MCPR SL. Also, the analyses demonstrate that when operating at ≥ 90% RTP with MCPR greater than or equal to the limit specified in the COLR, no RWE event will result in exceeding the MCPR SL (Ref. 3). Therefore, under these conditions, the RBM is also not required to be OPERABLE.

2. Rod Worth Minimizer

The RWM enforces a rod pattern which is consistent with the Banked Position Withdrawal Sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in References 4, 5, 6, 7, and 11. The standard BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control."

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 11) may be used if the coupling of each withdrawn control rod has been confirmed. The rods may be inserted without the need to stop at intermediate positions. When using the Reference 11 control rod insertion sequence for shutdown, the Rod Worth Minimizer may be reprogrammed to enforce the requirements of the improved BPWS control rod insertion process, or it can be bypassed if it is not programmed to reflect the optional BPWS shutdown sequence, as perfmitted by the Applicability Note for the RWM in Table 3.3.2.1-1.

The RWM Function satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

Since the RWM is a hardwired system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. 7). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Rod Worth Minimizer (continued)

pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% RTP, even though the RWM will enforce compliance with the BPWS when the reactor is at any power level. When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Refs. 5 and 7). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

3. Reactor Mode Switch — Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch — Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch — Shutdown Position Function satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5), no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Mode Switch — Shutdown Position (continued)

shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), provides the required control rod withdrawal blocks.

ACTIONS

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this reason, Required Action A.1 requires restoration of the inoperable channel to OPERABLE status. The Completion Time of 24 hours is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

B.1

If Required Action A.1 is not met and the associated Completion Time has expired, the inoperable channel must be placed in trip within 1 hour. If both RBM channels are inoperable, the RBM is not capable of performing its intended function; thus, one channel must also be placed in trip. This initiates a control rod withdrawal block, thereby ensuring that the RBM function is met.

The 1 hour Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities and is acceptable because it minimizes risk while allowing time for restoration or tripping of inoperable channels.

C.1, C.2.1.1, C.2.1.2, and C.2.2

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence.

(continued)

BASES

ACTIONS

C.1, C.2.1.1, C.2.1.2, and C.2.2 (continued)

However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or if a reactor startup with an inoperable RWM during withdrawal of one or more of the 12 rods was not performed in the last calendar year. These requirements minimize the number of reactor startups initiated with RWM inoperable. Required Actions C.2.1.1 and C.2.1.2 require verification of these conditions by review of plant logs and control room indications. Once Required Action C.2.1.1 or C.2.1.2 is satisfactorily completed, control rod withdrawal may proceed in accordance with the restrictions imposed by Required Action C.2.2.

Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff trained in accordance with an approved training program.

The RWM may be bypassed under these conditions to allow continued operations. In addition, Required Actions of LCO 3.1.3 and LCO 3.1.6 may require bypassing the RWM, during which time the RWM must be considered inoperable with Condition C entered and its Required Actions taken. Under these circumstances, movement of control rods is in compliance with the BPWS and Required Action C.2.2 is met, provided the number, type (e.g., stuck, slow, etc.) and separation criteria of Reference 6 are met.

D.1

With the RWM inoperable during a reactor shutdown, the operator is still capable of enforcing the prescribed control rod sequence. Required Action D.1 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff trained in accordance with an approved training program. The RWM may be bypassed under these conditions to allow the reactor shutdown to continue.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

With one Reactor Mode Switch — Shutdown Position control rod withdrawal block channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod withdrawal block function. However, since the Required Actions are consistent with the normal action of an OPERABLE Reactor Mode Switch — Shutdown Position Function (i.e., maintaining all control rods inserted), there is no distinction between having one or two channels inoperable.

In both cases (one or both channels inoperable), suspending all control rod withdrawal and initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies will ensure that the core is subcritical with adequate SDM ensured by LCO 3.1.1. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are therefore not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a second Note to indicate that when an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 9) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that a control rod block will be initiated when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. It includes the Reactor Manual Control Multiplexing System input.

Testing of the Reactor Manual Control Multiplexing System input shall include inputs of "no rod selected," "peripheral rod selected," and "center rod selected with two, three, or four LPRM strings around it" (Ref. 10).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on reliability analyses (Ref. 8).

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs and for SR 3.3.2.1.2, and by attempting to select a control rod, in each fully inserted group, not in compliance with the prescribed sequence and verifying a selection error occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn at $\leq$ 10% RTP in MODE 2, and SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is $\leq$ 10% RTP in

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.2 and SR 3.3.2.1.3 (continued)

MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 10% RTP for SR 3.3.2.1.3, to perform the required Surveillance if the Surveillance Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequencies are based on reliability analysis (Ref. 8).

SR 3.3.2.1.4

The RBM setpoints are automatically varied as a function of power. Three Allowable Values are specified in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values, which are verified during the CHANNEL CALIBRATION, automatically change are based on the APRM signal's input to each RBM channel. Below the minimum power setpoint, the RBM is automatically bypassed. These power Allowable Values must be verified periodically to be within the specified ranges to ensure that the Analytical Limits for the ranges specified in Table 3.3.2.1-1 are met. If any power range setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the power range channel can be placed in the conservative condition (i.e., enabling the proper RBM setpoint). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the actual trip setpoint methodology utilized for these channels.

SR 3.3.2.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.5 (continued)

CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the DAEC Instrument Setpoint Methodology.

As noted, neutron detectors are excluded from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.1.6

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch □ Shutdown Position Function to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch □ Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs. As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the Surveillance Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.6 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the on this Frequency.

SR 3.3.2.1.7

The RWM will only enforce the proper control rod sequence if the rod sequences are properly input into the RWM computer. This SR ensures that the proper sequences are loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring the RWM OPERABLE following loading of a sequence into the RWM, since this is when rod sequence input errors are possible.

(continued)

BASES

REFERENCES

1. UFSAR, Section 7.6.1.8.

2. UFSAR, Section 7.7.7.

3. UFSAR, Section 15.1.4.1.

4. NEDE-24011-P-A-US, "General Electrical Standard Application for Reload Fuel," Supplement for United States, Section S 2.2.3.1.

5. "Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners' Group, July 1986.

6. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

7. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Revision 17," December 27, 1987.

8. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.

9. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

10. Licensee Event Report #97-07, "Inadequate Testing of the Reactor Mode Switch to Shutdown Position Rod Block Function and Rod Block Monitor."

11. NEDO-33091-A, Rev. 2, “Improved BPWS Control Rod Insertion Process,” July 2004.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to determine that the actions automatically initiated by the Engineered Safety Features (ESF) equipment have successfully accomplished their safety functions for Design Basis Events. The instruments that monitor these variables are designated as non-Type A, Category I, in accordance with Regulatory Guide 1.97 (Ref. 1). Note that since the ESF at the DAEC accomplish their safety functions by automatic control, the DAEC does not have any Type A, Category I variables (Ref. 2).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1, as modified by Reference 3.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures OPERABILITY of Category I, non-Type A, variables so that the control room operating staff can:

Determine whether systems important to safety are performing their intended functions;

Determine the potential for causing a gross breach of the barriers to radioactivity release;

Determine whether a gross breach of a barrier has occurred; and

Initiate action necessary to protect the public and for an estimate of the magnitude of any impending threat.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The plant specific Regulatory Guide 1.97 Safety Evaluation Report (Ref. 2) found that DAEC is in conformance with, or is justified in deviating from the guidance of Regulatory Guide 1.97 for each Post Accident Monitoring variable, as modified by Reference 3. Category I, non-Type A, instrumentation is retained in Technical Specifications (TS) because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I instruments are important for reducing public risk and satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

LCO 3.3.3.1 requires at least two OPERABLE channels for all applicable Functions (except some Primary Containment Isolation Valve (PCIV) Position Functions, as allowed by Footnotes (a) and (b) to Table 3.3.3.1-1) to ensure that no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following an accident. Provision for at least two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

Exceptions to the two channel requirement are allowed for some PCIV position indications. In these cases, the important information is the status of the primary containment penetrations. The LCO requires two position indicators for each primary containment penetration flow path. In most cases, this requires one position indicator for each PCIV in the penetration, which is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of passive valve or via system boundary status. Exceptions are provided by footnotes to Table 3.3.3.1-1, for situations such as when normally active PCIVs are known to be closed and deactivated. For such situations, position indication is not needed to determine status. Therefore, the position indication for valves in these states are not required to be OPERABLE. An exception is also allowed for penetration flow paths with only one installed control room indication channel. For such situations, only one position indication channel is required to be OPERABLE.

(continued)

BASES

LCO (continued)

The following list is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1 in the accompanying LCO.

1. Reactor Steam Dome Pressure

Reactor steam dome pressure is a Category I variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig (i.e., wide range) monitor pressure. The pressure transmitters provide input both to pressure indicators and recorders. Wide range indicators and recorders are the primary indication used by the operator during an accident. A channel is considered OPERABLE if either the indicator or recorder is OPERABLE, or if the HPCI or RCIC steam line pressure indicator is OPERABLE, provided at least one channel is continuously recorded. If no channel is recorded, both channels must be declared inoperable and the appropriate Condition entered. Therefore, the PAM Specification deals primarily with this portion of the instrument channel. The HPCI and RCIC steam line pressure indicators (both with a range of 0 psig to 1500 psig) also provide backup means of monitoring reactor steam dome pressure and meet the required qualification requirements for Category I instrumentation.

2. Reactor Vessel Water Level

Reactor vessel water level is a Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. The wide range water level channels, in combination with the fuel zone level channels, provide the PAM Reactor Vessel Water Level Function. The wide range water level channels measure from 218 inches above the Top of Active Fuel (TAF) down to a point eight inches above the TAF. The fuel zone level channels measure from 218 inches above the TAF to a level below the bottom of the core support plate, or 153 inches below the TAF. Wide range water level is measured by two independent level transmitters. The output from these channels is displayed

(continued)

BASES

LCO

2. Reactor Vessel Water Level (continued)

by two independent level indicators and is one of the primary indications used by the operator during an accident. The other primary indication used by the operator during an accident is the fuel zone water level, which is measured by four level transmitters (two of which provide input to one channel with the other two level transmitters providing input to the other channel). The output from each channel is displayed on an independent level indicator and recorded on an independent recorder. A channel is considered OPERABLE if either the level indicator or recorder is OPERABLE, provided at least one channel is continuously recorded. If no channel is recorded, both channels must be declared inoperable and the appropriate condition entered. Therefore, the PAM Specification deals specifically with these portions of the instrument channels.

The wide range water level instruments are compensated for variation in reactor water density and are calibrated to be most accurate at operational pressure and temperature, while the fuel zone level instruments are uncompensated for recirculation pump flow, and are most accurate under no flow conditions.

3. Suppression Pool Water Level

Suppression pool water level is a Category I variable provided to detect a breach in the Reactor Coolant Pressure Boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. The wide range suppression pool water level measurement provides the operator with sufficient information to assess the status of both the RCPB and the water supply to the ECCS. The wide range water level indicators monitor the suppression pool water level from 1.5 feet above the bottom of the pool to 16 feet above the bottom of the pool. The primary means of monitoring this variable is from two wide range suppression pool water level signals that are transmitted from individual level transmitters. Each channel consists of an independent level indicator, and an independent recorder. A channel is considered OPERABLE if either the level indicator or the recorder is OPERABLE, provided at least one channel is continuously recorded. If no channel

(continued)

BASES

LCO

3. Suppression Pool Water Level (continued)

is recorded, both channels must be declared inoperable and the appropriate condition entered. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

4. Drywell Pressure

Drywell pressure is a Category I variable provided to detect a breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Two narrow range drywell pressure signals are transmitted from separate pressure transmitters. Each of these pressure transmitters feeds a signal to both a pressure indicator and a recorder, which indicate from -5 psig to +5 psig. Two wide range drywell pressure signals are also transmitted from separate pressure transmitters and are continuously recorded and displayed on two control room recorders. This portion of the channel (i.e., wide range) covers the pressure range for pressures greater than 5 psig (the recorder range is 0 psig to 250 psig). (Note: while the wide range transmitters also feed individual indicators, the indicated range is only 0 to 100 psig, which does not meet the Regulatory Guide 1.97 required range for this variable of 4 times the design pressure of 56 psig, and thus is not used to define channel OPERABILITY.) Both a narrow range instrument (i.e., either an indicator or recorder) and a wide range instrument (i.e., a recorder) are required to be OPERABLE in order for a channel of the Drywell Pressure Function to be considered OPERABLE. However, the full range (-5 psig to +250 psig) of drywell pressure must be continuously recorded, using any combination of transmitters and recorders. If the full range is not being continuously recorded, all channels must be declared inoperable and the appropriate Condition entered. These instruments (i.e., indicators and recorders) are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5. Primary Containment Area Radiation

Primary containment area radiation is a Category I variable provided to monitor the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency

(continued)

BASES

LCO

5. Primary Containment Area Radiation (continued)

plans. For the DAEC, primary containment area radiation PAM instrumentation consists of the following: 1) Two independent channels of drywell area radiation monitoring; each channel consists of a radiation element, which transmits a signal to a radiation indicating monitor and to a recorder; and, 2) Two independent channels of suppression chamber area radiation monitoring; each channel consists of a radiation element, which transmits a signal to a radiation indicating monitor and to a recorder that receives a companion input from the drywell area channel, noted above. For both the drywell area and suppression chamber area radiation monitoring channels, a channel is considered OPERABLE if either the radiation indicating monitor or recorder is OPERABLE, provided at least one channel is continuously recorded. If no channel is recorded, both channels must be declared inoperable and the appropriate Condition entered.

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position (excluding manual valves, check valves, excess flow check valves and relief valves), is a Category I variable provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE.

For the DAEC, the PCIV position PAM instrumentation consists of the individual open (i.e., red) and closed (i.e., green)

(continued)

BASES

LCO

6. Primary Containment Isolation Valve (PCIV) Position
(continued)

position indicating lights for each active PCIV. These indicating lights are located on various control panels in the control room.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to diagnosing the success of the automatic actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate Functions or for separate penetration flow paths for the PCIV Position Function. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function including separate Condition entry for each penetration flow path for the PCIV Position Function.

(continued)

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.6, which requires a written report to be submitted to the NRC. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information.

(continued)

BASES

ACTIONS

C.1 (continued)

Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

For the majority of Functions in Table 3.3.3.1-1, if the Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.6. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The following SRs apply to the PAM instrumentation Functions in Table 3.3.3.1-1, except as noted.

SR 3.3.3.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel against a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The HPCI and RCIC steam line instrumentation of the reactor steam dome pressure Function are compared to each other to satisfy this SR. For PCIV position indication, the CHANNEL CHECK consists of a comparison of the open and closed position lights with the expected position of the PCIV.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon plant operating experience, with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in this interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.1.2

A CHANNEL CALIBRATION is performed approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies the channel responds to the measured parameter with the necessary range and accuracy. For PCIV position indication, the CHANNEL CALIBRATION is a comparison of a local visual check to remote control room indication to verify the PCIV's indicated position agrees with the actual position. If an indication does not agree with the actual position, adjustments are made to the PCIV's indication channel. For Primary Containment Area Radiation instrumentation (Drywell and Suppression Chamber), the CHANNEL CALIBRATION shall consist of an electronic calibration of the channel for ranges above 10 R/hr and a one point calibration check of the detector below 10 R/hr with a portable gamma source.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience and consistency with the typical industry refueling cycles.

REFERENCES

1. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," December 1980.

2. R. M. Pulsifer (NRC) to L. Liu (IELP), "Duane Arnold Energy Center - Conformance to Regulatory Guide 1.97, Revision 2 (TAC M84788)," dated August 4, 1993.

3. DAEC License Revision 254, transmitted by letter, D. Beaulieu (USNRC) to M. Peifer (NMC), “Duane Arnold Energy Center – Issuance ofRevision Re: Relocation of Requirements for Hydrogen and Oxygen Monitors,” dated June 10, 2004.

B 3.3 INSTRUMENTATION

B 3.3.3.2 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the safety relief valves and the Residual Heat Removal Shutdown Cooling System can be used to remove core decay heat and meet all safety requirements. The ability to operate shutdown cooling from outside the control room allows operation in MODE 3 and the capability to place the plant in MODE 4 provides long term core decay heat removal.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the plant in MODE 3. Once in MODE 3, additional controls and indication necessary to transition to MODE 4 are available. Not all controls and necessary transfer switches are located at the remote shutdown panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The plant is in MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for a period of time.

The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in the UFSAR, Section 7.4.2 (Ref. 1).

The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it has been retained in the Technical Specifications (TS). The Remote Shutdown System satisfies criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room. The instrumentation and transfer/control Functions required are listed in Bases Table B 3.3.3.2-1. For the Transfer/Control circuits, the number shown in the table is the number of transfer switch circuits required.

The controls, instrumentation, and transfer switches are those required for:

- Reactor Pressure Vessel (RPV) pressure control;
- Decay heat removal;
- RPV inventory control; and
- Safety support systems for the above functions, including service water, component cooling water, and onsite power, including the diesel generators.

Pump ammeters, reactor head vents, and Reactor Feed Pump RPV High Level Trip Function, while installed in the Remote Shutdown Panels, are not required in order to consider the Remote Shutdown System OPERABLE. The Remote Shutdown System is OPERABLE if all instrument channels and transfer/control circuits needed to support the remote shutdown function are OPERABLE.

(continued)

BASES

LCO (continued)

The Remote Shutdown System instruments and transfer/control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instruments and transfer/control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1 and 2. This is required so that the plant can be placed and maintained in MODE 3 for a period of time from a location other than the control room.

This LCO is not applicable in MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, the TS do not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

A Note has been provided to modify the ACTIONS related to Remote Shutdown System Functions. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Remote Shutdown System Functions provide appropriate compensatory measures for separate Functions.

(continued)

BASES

ACTIONS (continued)

As such, a Note has been provided that allows separate Condition entry for each inoperable Remote Shutdown System Function.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System is inoperable. This includes any instrument channel Function listed in Table B 3.3.3.2-1, as well as the transfer/control circuit Functions.

The Required Action is to restore the Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

If the Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1

SR 3.3.3.2.1 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience demonstrates that Remote Shutdown System control channels usually pass the Surveillance when performed at this Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor for each of the instrument channel functions. The test verifies the channel responds to measured parameter values with the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. UFSAR, Section 7.4.2.

(continued)

TABLE B 3.3.3.2-1 (PAGE 1 OF 2)

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION

FUNCTION	REQUIRED NUMBER OF CHANNELS
Instrument Parameter	
1. Reactor Pressure Vessel Pressure Control	
a) Reactor Pressure	1
2. Reactor Pressure Vessel Inventory Control	
a) Reactor Level Wide Range	1
b) Reactor Level (Floodup)	1
c) B Core Spray Discharge Flow	1
3. Decay Heat Removal	
a) B RHR Loop Flow	1
b) B RHRSW Loop Flow	1
c) B RHR Heat Exchanger Shell Pressure	1
4. Safety Support Systems	
a) Torus Level	1
b) Torus Temperature	1
Transfer/Control Functions	
1. Reactor Pressure Vessel Pressure Control	
a) SRVs (Manual and Self-actuating)	2
b) SRVs (Self-actuating only)	(a)
c) SRVs (Self-actuating only)	1
d) Reactor Pressure Instrumentation	(b)
e) Emergency Fuses	(c)
2. Reactor Pressure Vessel Inventory Control	
a) B Core Spray MOVs	3
b) B Core Spray Pump	1
c) RCIC RPV High Level Shutdown/Restart	(d)
d) Outboard MSIVs	4
e) Closes Outboard MSL Drain MO-4424	1
f) HPCI RPV High Level Shutdown/Restart	1
g) Reactor Level Floodup Instrumentation	(b)
h) Reactor Level Wide Range and B Core Spray Discharge Flow Instrumentation	(e)
i) Emergency Fuses	(c)
3. Decay Heat Removal	
a) B RHR MOVs	7
b) B RHR Pumps	1
c) B RHRSW MOV and Closes RHR Radwaste Isolation MO-1937	1
d) B RHRSW Pumps	1
e) Closes RHR Cross-tie MO-2010	(d)

(continued)

TABLE B 3.3.3.2-1 (PAGE 2 OF 2)

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION

FUNCTION	REQUIRED NUMBER OF CHANNELS
3. Decay Heat Removal (continued)	
f) RHR SDC 135 psig Permissive	1
g) A RHR Pump Suction MOVs and Emergency Fuses	1
h) B RHR Loop Flow and B RHRSW Loop Flow Instrumentation	1
i) B RHR Heat Exchanger Shell Pressure Instrumentation	(e)
j) Emergency Fuses	(c)
4. Safety Support Systems	
a) B ESW Pump	1
b) B RWS Pumps	1
c) Aligns B RWS Makeup Valves	(a)
d) B DG Controls and Emergency Fuses	2
e) B Essential 4160 Instrumentation	1
f) B Essential 4160 and 480 Breakers	6
g) Starts B RHR/CS and DG Room Cooling Fans	1
h) Starts B Battery Exhaust Fan Enables B DG Fuel Oil Transfer Pump	1
i) Opens Containment N_2 Supply CV-4371A	1
j) Torus Water Level and Torus Water Temperature Instrumentation	(b)
k) Emergency Fuses	(c)

(a) One switch is required and transfers both functions annotated with this note.
(b) One switch is required and transfers all three functions annotated with this note.
(c) One switch is required and transfers fuses for all four functions annotated with this note.
(d) One switch transfers both functions annotated with this note.
(e) One switch transfers both functions annotated with this note.

B 3.3 INSTRUMENTATION

B 3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

BASES

BACKGROUND

The EOC-RPT instrumentation initiates a Recirculation Pump Trip (RPT) to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to core thermal MCPR Safety Limits (SLs).

The need for the additional negative reactivity in excess of that normally inserted on a scram reflects end of cycle reactivity considerations. The scram reactivity depends on the ability of the control rods to be in the high flux regions of the core. The minimum scram reactivity occurs at the end of cycle when control rods are fully withdrawn from the core. In this situation, it takes a longer time for the control rods to travel to a high importance region in the core. For this reason at the end of cycle the control rods may not be able to ensure that thermal limits are maintained by inserting sufficient negative reactivity during the first few feet of rod travel upon a scram caused by Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure — Low or Turbine Stop Valve (TSV) — Closure. The physical phenomenon involved is that the positive reactivity feedback due to a pressurization transient (i.e., void collapse) can add positive reactivity at a faster rate than the control rods can add negative reactivity.

The EOC-RPT instrumentation, is composed of sensors that detect initiation of closure of the TSVs or fast closure of the TCVs, combined with relays, logic circuits, and fast acting circuit breakers that interrupt power from the recirculation pump Motor Generator (MG) set generators to each of the recirculation pump motors. The channels include electronic equipment (e.g., limit switches or pressure switches) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an EOC-RPT signal to the trip logic. When the RPT breakers trip open, the recirculation pumps coast down under their own inertia. The EOC-RPT has two identical trip systems, either of which can actuate an RPT in both recirculation loops.

(continued)

BASES

BACKGROUND (continued)

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TSV — Closure or two TCV Fast Closure, Trip Oil Pressure — Low signals are required for a trip system to actuate. If either trip system actuates, both recirculation pumps will trip. There are two EOC-RPT breakers in series per recirculation pump. One trip system trips one of the two EOC-RPT breakers for each recirculation pump, and the second trip system trips the other EOC-RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV — Closure and the TCV Fast Closure, Trip Oil Pressure — Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and pressurization transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that ensure EOC-RPT, are summarized in References 1, 2, and 3.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT, as specified in the COLR, are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when turbine first stage pressure is < 26% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

associated EOC-RPT breakers) must also respond within its assumed response time.

Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the Analytical Limit assumed in the transient and accident analysis in order to account for instrument uncertainties appropriate to the Function. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., TSV position), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., limit switch) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analysis, LCO, and Applicability discussions are listed below on a Function by Function basis.

Alternatively, since this instrumentation protects against a MCPR SL violation, with the instrumentation inoperable, modifications to the MCPR limits (LCO 3.2.2) may be applied to allow this LCO to be met. The MCPR penalty for the EOC-RPT inoperable condition is specified in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Stop Valve — Closure

Closure of the TSVs and a main turbine trip result in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TSV — Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Closure of the TSVs is determined by measuring the position of each valve. There is one position switch associated with each stop valve. The signals from two of the four valves are assigned to one trip system, while the signals from the other two valves are assigned to the other trip system. The logic for the TSV — Closure Function is such that either TSV 1 and TSV 2 must be less than fully open or TSV 3 and TSV 4 must be less than fully open to produce an EOC-RPT. This Function must be enabled whenever THERMAL POWER $\geq$ 26% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this Function nonconservatively (THERMAL POWER is derived from the turbine first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed in order to maintain this Function OPERABLE whenever THERMAL POWER $\geq$ 26% RTP (e.g., during TBV surveillance testing per SR 3.7.7.1). In addition, other steam loads, such as second stage reheaters in operation below 26% RTP, must be accounted for in establishing this setpoint. Otherwise, turbine first stage pressure would be non-conservative with respect to the 26% RTP RPS bypass. Four channels of TSV — Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV — Closure Allowable Value is selected to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is $\geq$ 26% RTP. Below 26% RTP, the Reactor Vessel Steam Dome Pressure — High and the Average Power Range Monitor (APRM) Fixed Neutron Flux — High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LOC and APPLICABILITY (continued)

Turbine Control Valve Fast Closure, Trip Oil Pressure — Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure — Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the electrohydraulic control fluid pressure at each control valve. There is one pressure switch associated with each control valve. The signal from two of the four valves are assigned one trip system, while the signals from the other two valves are assigned to the other trip system. The logic for the TCV Fast Closure, Trip Oil Pressure — Low Function is such that either TCV 1 and TCV 2 must be closed (pressure switch trips) or TCV 3 and TCV 4 must be closed to produce an EOC-RPT. This Function must be enabled whenever THERMAL POWER $\geq$ 26% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this Function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed in order to maintain this Function OPERABLE whenever THERMAL POWER is $\geq$ 26% RTP. In addition, other steam loads, such as second stage reheaters in operation below 26% RTP, must be accounted for in establishing this setpoint. Otherwise, turbine first stage pressure would be non-conservative with respect to the 26% RTP RPS bypass. Four channels of TCV Fast Closure, Trip Oil Pressure — Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure — Low Allowable Value is selected high enough to detect imminent TCV fast closure. The transient analysis assumes a response time of 30 msec (i.e., start of TCV closure from full open to switch actuation). The switch setting is selected to support this response time.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Turbine Control Valve Fast Closure, Trip Oil Pressure — Low (continued)

This protection is required consistent with the safety analysis whenever THERMAL POWER is ≥ 26% RTP. Below 26% RTP, the Reactor Vessel Steam Dome Pressure — High and the APRM Fixed Neutron Flux — High Functions of the RPS are adequate to maintain the necessary safety margins.

ACTIONS

A Note has been provided to modify the ACTIONS related to EOC-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable EOC-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable EOC-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Actions B.1 and B.2 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of an EOC-RPT, 72 hours is provided to restore the inoperable channels (Required Action A.1). Additionally, applying the EOC-RPT inoperable MCPR limit satisfies the LCO and is thus acceptable.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Alternately, the inoperable channels may be placed in trip (Required Action A.2) since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT, or if the inoperable channel is the result of an inoperable breaker), Condition C must be entered and its Required Actions taken.

B.1 and B.2

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining EOC-RPT trip capability. A Function is considered to be maintaining EOC-RPT trip capability when sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system, to each be OPERABLE or in trip, and the associated EOC-RPT breakers to be OPERABLE or in trip. Alternately, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

The 2 hour Completion Time is sufficient time for the operator to restore EOC-RPT trip capability or apply the MCPR penalty, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation. Once the MCPR penalty is applied, Required Action A.1 of LCO 3.2.2 allows 2 hours for MCPR to be restored within limits, if necessary.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 26% RTP within 4 hours. Alternately, the associated recirculation pump may be removed from service, since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 26% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

SR 3.3.4.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The RPT breaker is excluded from this testing.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on reliability analysis of Reference 4.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional test of the pump breakers is included as a part of this test, overlapping the LOGIC System Functional Test, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would also be inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

SR 3.3.4.1.4

This SR ensures that an EOC-RPT initiated from the TSV — Closure and TCV Fast Closure, Trip Oil Pressure — Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq$ 26% RTP. This involves calibration of the bypass channels. The 26% RTP is the analytical limit. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure) the main turbine bypass valves must remain closed whenever THERMAL POWER $\geq$ 26% RTP to ensure

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.4 (continued)

that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 26% RTP, either due to open main turbine bypass valves (e.g., required testing or upon actual demand) or other reasons), the affected TSV — Closure and TCV Fast Closure, Trip Oil Pressure — Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met with the channel considered OPERABLE.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgement and the reliability of the components.

SR 3.3.4.1.5

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the transient analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are documented in Reference 3.

EOC-RPT SYSTEM RESPONSE TIME test Frequency is controlled under the Surveillance Frequency Control Program. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, the Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 15.0.

2. UFSAR, Sections 15.1.2.1 and 15.1.2.2.

3. UFSAR, Section 7.2.1.2.3.

4. GENE-770-06-1, "Bases For Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND

The ATWS-RPT System initiates an RPT, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level — Low Low or Reactor Steam Dome Pressure — High setpoint is reached, the recirculation pump motor breakers trip.

The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability circuit breakers, and switches that are necessary to cause initiation of an RPT. The channels include electronic equipment (e.g., on-off sensors) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Steam Dome Pressure — High and two channels of Reactor Vessel Water Level — Low Low in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Water Level — Low Low or two Reactor Pressure — High signals are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that either trip system will trip both recirculation pumps (by tripping the associated pump motor breakers). Since redundancy in the ATWS-RPT is not required, only one of the two trip systems is required to be OPERABLE.

Each pump motor has two breakers in series between the pump motor and the recirculation motor generator set. One pump motor breaker in each recirculation loop is associated with one trip system, while the other pump motor breaker in each recirculation loop is associated with the other trip system, for a total of four breakers. The output of each trip system is provided to both associated recirculation pump breakers.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ATWS-RPT is not assumed to function during or after a design basis accident. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which a scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation is included as required by Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the ATWS-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have two OPERABLE channels in a trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.2.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump motor breakers. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Allowable Values are specified for each ATWS-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensors) changes state. Analytical Limits are the limiting values of the process parameters for use in safety analysis. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The individual Functions are required to be OPERABLE in MODE 1 to protect against common mode failures of the Reactor Protection System by providing a diverse trip to mitigate the consequences of a postulated ATWS event. The Reactor Steam Dome Pressure-High and Reactor Vessel Water Level-Low Low Functions are required to be OPERABLE in MODE 1, since the reactor is producing significant power and the recirculation system could be at high flow. During this MODE, the potential exists for pressure increases or low water level, assuming an ATWS event. In MODE 2, the reactor is at low power and the recirculation system is at low flow; thus, the potential is low for a pressure increase or low water level, assuming an ATWS event. Therefore, the ATWS-RPT is not necessary. In MODES 3 and 4, the reactor is shut down with all control rods inserted; thus, an ATWS event is not significant and the possibility of a significant pressure increase or low water level is negligible. In MODE 5, the one rod out interlock ensures that the reactor remains subcritical; thus, an ATWS event is not significant. In addition, the Reactor Pressure Vessel (RPV) head is not fully tensioned and no pressure transient threat to the Reactor Coolant Pressure Boundary (RCPB) exists.

The specific Applicable Safety Analyses and LCO discussions are listed below on a Function by Function basis.

a. Reactor Vessel Water Level — Low Low

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the ATWS-RPT System is initiated at Reactor Vessel Water Level-Low Low to aid in maintaining level above the top of the active fuel. The reduction of core flow reduces the neutron flux and THERMAL POWER and, therefore, the rate of coolant boiloff.

Reactor vessel water level signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Reactor Vessel Water Level — Low Low (continued)

Since redundancy is not required in the ATWS-RPT, two channels of Reactor Vessel Water Level — Low Low in a trip system are available and required to be OPERABLE. The Reactor Vessel Water Level — Low Low Allowable Value is chosen for convenience with the reactor core isolation cooling initiation. A 9 second time delay is incorporated into the RPT initiating signal of Reactor Vessel Water Level - Low Low. This delay is to allow the Low Pressure Coolant Injection System Loop Selection Logic to complete its function.

b. Reactor Steam Dome Pressure — High

Excessively high RPV pressure may rupture the RCPB. An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This increases neutron flux and THERMAL POWER, which could potentially result in fuel failure and overpressurization. The Reactor Steam Dome Pressure-High Function initiates an RPT for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power generation. For the overpressurization event, the RPT aids in the termination of the ATWS event and, along with the safety/relief valves, limits the peak RPV pressure to less than the ASME Section III Code Service Level C limits (1500 psig).

The Reactor Steam Dome Pressure — High signals are initiated from four pressure switches that monitor reactor steam dome pressure. However, since redundancy is not required in the ATWS-RPT, two channels of Reactor Steam Dome Pressure — High in a trip system are required to be OPERABLE. The Reactor Steam Dome Pressure — High Allowable Value is chosen to provide an adequate margin to the ASME Section III Code Service Level C allowable Reactor Coolant System pressure.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to ATWS-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ATWS-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ATWS-RPT instrumentation channel.

A.1

Required Action A.1 is intended to ensure that appropriate actions are taken if either a single channel is inoperable and untripped or if multiple, untripped channels within the same Function are inoperable such that the Function does not maintain ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when both channels in a trip system are OPERABLE or in trip, and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system to each be OPERABLE or in trip, and the recirculation pump motor breakers to be OPERABLE or in trip. However, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g. as in the case where placing the inoperable channel in trip would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition C must be entered and its Required Actions taken.

The 72 hour Completion Time is sufficient for the operator to take corrective action (i.e., place the channel in trip) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and that one instrumentation Function is still maintaining ATWS-RPT trip capability.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more channels for both Functions in a trip system inoperable, the ATWS-RPT System is not capable of performing the intended function. Required Action B.1 is intended to ensure that appropriate Actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. Therefore, a 1 hour Completion Time is provided to restore the inoperable channel. Alternately, the inoperable channel may be placed in trip since this would conservatively compensate for the inoperability and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition C must be entered and its Required Actions taken.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

C.1 and C.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 8 hours (Required Action C.2). Alternately, the associated recirculation pump may be removed from service since this performs the intended function of the instrumentation (Required Action C.1). The allowed Completion Times of 8 hours to reach MODE 2 from full power conditions and of 8 hours to remove a recirculation pump from service in an orderly manner and without challenging plant systems, are reasonable, based on operating experience.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.1

Performance of the CHANNEL CHECK for the Reactor Vessel Water Level-Low Low Function ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal but more frequent checks of channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.4.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The RPT breaker itself is excluded from this testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.2 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of is based on the fact that ATWS is considered a very low probability event and is outside the normal design basis. Therefore, the surveillance frequency is less stringent than for safety-related instrumentation.

SR 3.3.4.2.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Figure 7.2-10, ATWS-RPT Logic Diagram.

2. GENE-770-06-1, "Bases for Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

For most Abnormal Operational Transients and Design Basis Accidents (DBAs), a wide range of dependent and independent parameters are monitored.

The ECCS instrumentation actuates Core Spray (CS), Low Pressure Coolant Injection (LPCI), High Pressure Coolant Injection (HPCI), Automatic Depressurization System (ADS), and the Diesel Generators (DGs). The equipment involved with each of these systems is described in the Bases for LCO 3.5.1, "ECCS - Operating" or LCO 3.8.1, "AC Sources-Operating."

Core Spray System

The CS System may be initiated by either automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level — Low Low Low or Drywell Pressure — High. Each of these diverse variables is monitored by four redundant instruments, which are, in turn, connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic (i.e., two trip systems) for each Function.

Both initiation signals are sealed in signals and must be manually reset. The CS initiation logic can be reset when both the drywell pressure and the reactor water level have been restored. The CS pumps can be secured even with an initiation signal present. A "disagreement" light will illuminate if this situation occurs. Upon receipt of an initiation signal, the CS pumps are started after 5 seconds (nominal) if power is available. If power is unavailable, the CS pump will start 5 seconds (nominal) after power is restored to the associated essential bus.

(continued)

BASES

BACKGROUND Core Spray System (continued)

The CS test bypass valve, which is also a Primary Containment Isolation Valve (PCIV), is normally closed to maintain primary containment integrity, and also closes, if open, on a CS initiation signal to allow the assumed system flow to the Reactor Pressure Vessel (RPV). This design feature is not assumed in any accident analyses. The accident analyses are performed assuming the ECCS systems are in the standby readiness mode except that accidents are not assumed to initiate during unit testing.

The CS pump discharge flow is monitored by a flow transmitter. The minimum flow return line valve is normally open and is automatically closed if flow is above the minimum flow setpoint to allow the system flow assumed in the accident analysis.

The CS initiation logic also monitors the pressure in the RPV to ensure that, before the injection valves open, the RPV pressure has fallen to a value low enough that the low pressure portions of the CS System are not overpressurized. The variable is monitored by four redundant pressure switches, which are, in turn, connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic.

Low Pressure Coolant Injection System

LPCI is an operating mode of the Residual Heat Removal (RHR) System. The LPCI System may be initiated by automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level — Low Low Low or Drywell Pressure — High. Each of these diverse variables is monitored by four redundant instruments, which, in turn, are connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic (i.e., two trip systems) for each Function. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until both initiation signals clear and the logic is manually reset. The LPCI pumps can be secured even with an initiation signal present. A "disagreement" light will illuminate if this situation occurs.

(continued)

BASES

BACKGROUND Low Pressure Coolant Injection System (continued)

Upon receipt of an initiation signal, the A and B LPCI pumps start after a 10 second (nominal) delay if power is available. The C and D LPCI pumps are started after a 15 second (nominal) delay if power is available. The respective time delays are intended to limit the loading of the standby power sources. If power is unavailable, the respective LPCI pumps will start after power is restored to the respective emergency bus, and after the applicable time delay.

The LPCI System initiation logic also contains LPCI Loop Select Logic whose purpose is to identify and direct LPCI flow to the unbroken recirculation loop if a Design Basis Accident (DBA) occurs. The LPCI Loop Select Logic is initiated upon the receipt of either a Reactor Vessel Water Level - Low Low signal or a Drywell Pressure - High signal. The initiation signal also enables the output relay of the Recirc Riser differential pressure (dp) instrumentation. Each of these variables is monitored by four redundant instruments which are, in turn, connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic. When initiated, the LPCI Loop Select Logic first determines recirculation pump operation by sensing the dp between the suction and discharge of each pump. There are four dp switches in each recirculation loop which are, in turn, connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each recirculation pump. If the logic senses that either pump is not running, i.e., single loop operation, then a trip signal is sent to both recirculation pumps to eliminate the possibility of pipe breaks being masked by the operating recirculation pump pressure. If a pump trip signal is generated, RPV pressure must drop to a specified value before the logic will continue. This adjusts the selection time to optimize sensitivity and still ensure that LPCI injection is not unnecessarily delayed. The RPV pressure is sensed by four pressure switches that are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. After the satisfaction of this pressure requirement or if both recirculation pumps indicate they are running, a time delay is provided to remove initial pressure perturbations and allow momentum effects of the pump coastdown to settle out. Selection of the unbroken recirculation loop is then initiated. This is done by comparing the absolute pressure of the two

(continued)

BASES

BACKGROUND Low Pressure Coolant Injection System (continued)

recirculation loops. The broken loop is indicated by a lower pressure than the unbroken loop. The loop with the higher pressure is then used for LPCI injection. If, after a small time delay, the pressure in loop A is not indicating higher than loop B, the logic will provide a signal to close the B recirculation loop discharge and discharge bypass valves, open the LPCI injection valve to the B recirculation loop and close the LPCI injection valve to the A recirculation loop. This is the "default" choice in the LPCI Loop Select Logic. (However, the discharge bypass valves are not environmentally - qualified and the DAEC accident analysis (Ref. 2) assumes that they remain open and divert some flow out of the pipe break.) If recirculation loop A pressure indicates higher than loop B pressure, the recirculation valves in loop A are closed, the LPCI injection valve to loop A is signaled to open and the LPCI injection valve to loop B is signaled to close. The four differential pressure transmitters/alarm units which provide input to this portion of the logic detect the pressure difference between the corresponding risers to the jet pumps in each recirculation loop. The four differential pressure transmitters/alarm units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. There are two redundant trip systems in the LPCI Loop Select Logic.

The LPCI System's two discharge flow paths are monitored by flow transmitters which provide input to the two minimum flow return line valves. The two Division 1 pumps are associated with one minimum flow return line, and the two Division 2 pumps are associated with the other minimum flow return line. When a pump is running and discharge flow is low enough so that pump overheating may occur, the respective minimum flow return line valve is opened. If flow is above the minimum flow setpoint, the valve is automatically closed to allow the system flow assumed in the analyses.

The RHR test line suppression pool cooling isolation valve, suppression pool spray isolation valves, and containment spray isolation valves (which are also PCIVs) are normally closed to maintain primary containment integrity, and also close, if open, on a LPCI initiation signal to allow the assumed system flow to the RPV. These design features are not assumed in any accident analyses. The accident analyses

(continued)

BASES

BACKGROUND Low Pressure Coolant Injection System (continued)

are performed assuming the ECCS systems are in the standby readiness condition when the accident occurs.

The LPCI initiation logic monitors the pressure in the RPV to ensure that, before an injection valve opens, the RPV pressure has fallen to a value low enough that the low pressure portions of the LPCI System are not overpressurized. The variable is monitored by four redundant pressure switches, which are, in turn, connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic.

Low reactor water level in the shroud is detected by four additional instruments to allow the use of other modes of RHR (e.g., suppression pool cooling) when a LPCI initiation signal is present. These instruments allow containment cooling to be performed if the level in the shroud is above the prescribed setpoint.

High Pressure Coolant Injection System

The HPCI System may be initiated by either automatic or manual means although manual initiation requires manipulation of individual component control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level — Low Low or Drywell Pressure — High. Each of these variables is monitored by four redundant instruments, which are, in turn, connected to four relays whose contacts are arranged in a one-out-of-two taken twice logic for each Function.

The HPCI pump discharge flow is monitored by a flow transmitter. When the pump is running and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the system flow assumed in the accident analysis.

The HPCI test return valve and redundant shutoff valve are closed upon receipt of a HPCI initiation signal to allow the assumed system flow to the RPV. This design feature is not assumed in any accident analyses. The accident analyses are performed assuming the ECCS are in the standby readiness

(continued)

BASES

BACKGROUND High Pressure Coolant Injection System (continued)

condition when the accident occurs. These valves are also closed if either suppression pool suction valve is full open. This prevents pumping suppression pool water to the Condensate Storage Tank (CST).

The HPCI System also monitors the water levels in the Condensate Storage Tank (CST) and the suppression pool because these are the two sources of water for HPCI operation. Reactor grade water in the CST is the preferred source although this source would not necessarily be available under accident conditions. Upon receipt of a HPCI initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless both suppression pool suction valves are open. If the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in the CST. Either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The HPCI System provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level — High trip, at which time the HPCI turbine trips, which causes the turbine's stop valves, injection valve and minimum flow valve to close. The logic is two-out-of-two once to provide high reliability of the HPCI System. The HPCI System automatically restarts if a Reactor Vessel Water Level — Low Low signal is subsequently received.

Automatic Depressurization System

The ADS may be initiated either automatically or by manually opening the individual valves using the corresponding handswitches. Automatic initiation occurs when signals indicating Reactor Vessel Water Level — Low Low Low; confirmed Reactor Vessel Water Level — Low, and CS or LPCI Pump Discharge Pressure — High are all present and the ADS

(continued)

BASES

BACKGROUND Automatic Depressurization System (continued)

Timer has timed out. There are two level switches for Reactor Vessel Water Level — Low Low and one level switch for confirmed Reactor Vessel Water Level — Low, in each of the two ADS trip logics. Each of these level switches connects to a relay whose contacts form the initiation logic.

Each ADS trip logic includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The ADS Timer time delay setpoint chosen is long enough that the HPCI has sufficient operating time to recover to a level above Reactor Vessel Water Level-Low Low, yet not so long that the LPCI and CS Systems are unable to adequately cool the fuel if the HPCI fails to maintain that level. An alarm in the control room is annunciated when either of the timers is timing. Resetting the ADS initiation signals resets the ADS Timers. In addition, these timers can be manually overridden to preclude an unnecessary RPV depressurization.

The ADS also monitors the discharge pressures of the four LPCI pumps and the two CS pumps. Each ADS trip logic includes two discharge pressure permissive switches from each of the following: one CS pump and two LPCI pumps in the associated Division (i.e., Division 1 LPCI pumps A and C input to ADS trip logic A, and Division 2 LPCI pumps B and D input to ADS trip logic B). The signals are used as a permissive for ADS actuation, indicating that there is a source of core coolant available once the ADS has depressurized the vessel. Any one of the six low pressure pumps is sufficient to provide adequate core cooling for a small break LOCA and permit automatic depressurization.

The logic scheme used for initiating the ADS System is a single trip system that contains two logics (the A logic and the B logic). Each logic can initiate opening all four ADS valves to effect automatic depressurization. The A logic is powered from Division 1 of the 125 V DC System, while logic B can be powered from either Division of the 125 V DC System. Also, each ADS solenoid valve and its associated portion of the actuation logic can be powered from either Division of the 125 V DC System. Each logic is arranged such that all of the following must occur to cause ADS actuation:

(continued)

BASES

BACKGROUND Automatic Depressurization System (continued)

1) two-out-of-two Reactor Vessel Water Level - Low Low switches must actuate, 2) the single Reactor Vessel Water Level - Low switch must actuate, 3) one-out-of-three taken twice Pump Discharge Pressure switches must actuate, and 4) the single ADS Timer must time out. The ADS Timer begins its timing sequence when the associated Reactor Vessel Water Level - Low Low Low and confirmatory Reactor vessel Water Level - Low signals are present. Once the ADS initiation signal is present, it is sealed in until manually reset. A reset pushbutton permits the ADS Timer to begin the timing sequence anew anytime before the Timer has timed out. ADS initiation can also be prevented by placing the reset handswitch in the Override position. Neither the reset pushbutton nor the reset handswitch is required for ADS OPERABILITY.

Diesel Generators

The DGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level — Low Low Low or Drywell Pressure — High. The DGs are also initiated upon loss of voltage signals. (Refer to the Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) Each of these diverse variables is monitored by four redundant instruments, which are, in turn, connected to four relays whose contacts are connected to a one-out-of-two taken twice logic to initiate both DGs 1G-31 and 1G-21. The DGs receive their initiation signals from the CS System initiation logic. The DGs can also be started manually from the control room and locally from the associated DG room. The DG initiation signal is a sealed in signal and can be manually reset. The DG initiation logic is reset by resetting the associated CS System initiation logic. Upon receipt of a Loss of Coolant Accident (LOCA) initiation signal, each DG is automatically started, is ready to load in approximately 10 seconds, and will run in standby conditions (rated voltage and speed, with the DG output breaker open). The DGs will only energize their respective Engineered Safety Feature buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1.).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2 and 3. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the ECCS instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Table 3.3.5.1-1 is modified by a footnote which is added to show that certain ECCS instrumentation Functions also perform DG initiation.

Allowable Values are specified for each ECCS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel waterlevel), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor or bi-stable trip circuit) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or DG) initiation to mitigate the consequences of an abnormal operational transient or design basis accident. To ensure reliable ECCS and DG function, a combination of Functions is required to provide primary and secondary initiation signals.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Vessel Water Level — Low Low Low

Low Reactor Pressure Vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated DGs are initiated at Reactor Vessel Water Level-Low Low Low to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. Reactor Vessel Water Level — Low Low Low is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 3 and 4. In addition, the Reactor Vessel Water Level — Low Low Low Function is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 2.a Reactor Vessel Water Level - Low Low Low (continued)

Reactor Vessel Water Level — Low Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level — Low Low Low Allowable Value is chosen to allow time for the low pressure core flooding LCO, and systems to activate and provide adequate cooling.

Four channels of Reactor Vessel Water Level — Low Low Low Function are only required to be OPERABLE when the ECCS are required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation.

1.b, 2.b. Drywell Pressure — High

High pressure in the drywell could indicate a break in the Reactor Coolant Pressure Boundary (RCPB). The low pressure ECCS and associated DGs are initiated upon receipt of the Drywell Pressure — High Function in order to minimize the possibility of fuel damage. The Drywell Pressure — High Function, along with the Reactor Water Level — Low Low Low Function, is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure switches that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b, 2.b. Drywell Pressure — High (continued)

The Drywell Pressure — High Function is required to be OPERABLE when the ECCS or DG is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the CS Drywell Pressure — High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude CS and DG initiation. Also, the LPCI Drywell Pressure - High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure no single instrument failure can preclude LPCI initiation. In MODES 4 and 5, the Drywell Pressure — High Function is not required, since there is insufficient energy in the reactor to pressurize the primary containment to Drywell Pressure — High setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems and to LCO 3.8.1 for Applicability Bases for the DGs.

1.c, 2.c. Reactor Steam Dome Pressure — Low (Injection Permissive)

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Steam Dome Pressure — Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 3 and 4. In addition, the Reactor Steam Dome Pressure — Low Function is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Steam Dome Pressure — Low signals are initiated from four pressure switches that sense the reactor dome pressure.

The Allowable Value is low enough to prevent over- pressurizing the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 2.c. Reactor Steam Dome Pressure — Low (Injection Permissive) (continued)

Four channels of Reactor Steam Dome Pressure — Low Function are only required to be OPERABLE when the ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

1.d, 2.f. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow — Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump(s) from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valves (normally open for the CS System and normally closed for the LPCI System) receive an open signal when low flow is sensed, and automatically close when the flow rate is adequate to protect the associated pump. The LPCI and CS Pump Discharge Flow — Low Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flow rates assumed during the transients and accidents analyzed in References 1, 2, and 3 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch per CS pump and one differential pressure switch for the two RHR pumps in each division are used to detect the associated subsystems' flow rates. The logic is arranged such that each differential pressure switch or flow switch causes its associated minimum flow valve to receive an open signal. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the switches detect low flow. The time delay is provided by design to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode although, typically, the minimum flow valves are prevented from opening when operating in the shutdown cooling mode. The Pump Discharge Flow — Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.d, 2.f. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow-Low (Bypass) (continued)

that the closure of the minimum flow valve is initiated to allow the assumed flow into the core. Each channel of Pump Discharge Flow — Low Function (two CS channels, one per pump and two LPCI channels, one per loop) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude the ECCS function.* Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

2.d. Reactor Vessel Shroud Level — Low

The Reactor Vessel Shroud Level-Low Function is provided as a permissive to allow the RHR System to be manually aligned from the LPCI mode to the suppression pool cooling/spray or drywell spray modes with a LPCI initiation signal still present. This function ensures: 1) that the permissive is removed prior to reaching two thirds core height when vessel level is decreasing, and 2) that the permissive is not restored until two thirds core height is reached when vessel level is increasing. This ensures that LPCI is available to prevent or minimize fuel damage. This function may be overridden during accident conditions as allowed by plant procedures to allow containment cooling/spray regardless of the level present in the shroud.

Reactor Vessel Shroud Level — Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Shroud Level — Low Allowable Value is chosen to allow the low pressure core flooding systems to activate and provide adequate cooling before allowing a manual transfer.

Four channels of the Reactor Vessel Shroud Level — Low Function are only required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the specified initiation time of the LPCI subsystems is not assumed, and other administrative controls are adequate to control the valves that this Function isolates (since the containment cooling mode of RHR is not required to be OPERABLE in MODES 4 and 5 and is normally not used).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.e, 2.e Core Spray Pump Startup - Time Delay Relay and Low Pressure Coolant Injection Pump Start - Time Delay Relay

The purpose of these time delay relays is to stagger the start of the CS pumps and LPCI pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV emergency buses. This Function is only necessary when power is being supplied from the standby power sources (DG). However, since the time delay does not degrade ECCS operation, it remains in the pump start logic at all times. The CS Pump and LPCI Pump Start — Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analyses assume that the pumps will initiate when required and excess loading will not cause failure of the standby power sources.

There are two CS Pump Start - Time Delay Relays and four LPCI Pump Start - Time Delay Relays, one in each of the CS and RHR pump start logic circuits. While each time delay relay is dedicated to a single pump start logic, a single failure of a CS Pump Start - Time Delay Relay or of a LPCI Pump Start - Time Delay Relay could result in the failure of the three low pressure ECCS pumps, powered from the same emergency bus if the emergency bus is being powered by its associated DG, to perform their intended function within the assumed time (e.g., as in the case where two or more ECCS pumps on one emergency bus start simultaneously due to an inoperable time delay relay which, in turn cause the associated DG output breaker to trip open due to undervoltage conditions). This still leaves three of the six low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Value for the CS Pump Start-Time Delay Relay and each LPCI Pump Start — Time Delay Relay is chosen to be long enough so that most of the starting transient of one pump is complete before starting another pump on the same 4.16 kV emergency bus and short enough so that ECCS operation is not degraded.

Each CS Pump Start - Time Delay Relay and each LPCI Pump Start - Time Delay Relay Function is required to be OPERABLE only when the associated CS or LPCI System is required to be OPERABLE. Refer to LCO 3.5.1 for Applicability Bases for the CS and LPCI Systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.f 2.k 4.16 kV Emergency Bus Sequential Loading Relay

An undervoltage condition on an emergency bus indicates that sufficient power (from either the offsite or onsite sources) is not available to allow starting of the low pressure ECCS pumps. Therefore, if this condition exists, the start permissive signal is withheld from the circuits that start both the Core Spray (CS) and Low Pressure Coolant Injection (LPCI) pumps during accident conditions, and the CS and LPCI pumps powered from the respective emergency bus are prevented from starting. This ensures that the low pressure ECCS pumps are not started during accident conditions unless adequate power is available.

Each emergency bus is monitored by a single relay, which inputs into a one-out-of-two once logic for each division. Each logic channel supports one CS and two LPCI pumps. An instrument channel consists of the common bus monitoring relay and the associated relay contacts for each ECCS pump.

The 4.16 kV Emergency Bus Sequential Loading Relay Allowable Values are low enough to prevent low pressure ECCS pump starting unless adequate power is available, but high enough so that low pressure ECCS pump starting is not unnecessarily prohibited or delayed and is within the maximum adjustable range of the relay.

To ensure that no single failure can prevent successful operation of the combined low pressure ECCS, two channels of the 4.16 kV Emergency Bus Sequential Loading Relay Function are required to be OPERABLE whenever the LPCI System is required to be OPERABLE (i.e., MODES 1, 2, and 3). Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the CS and LPCI Systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.g. LPCI Loop Select - Reactor Vessel Water Level - Low Low

The purpose of the LPCI Loop Select Reactor Vessel Water Level - Low Low Function is to initiate the LPCI Loop Select Logic at a level slightly higher than the level that starts the low pressure ECCS pumps (the LPCI Loop Select Logic can also be initiated simultaneously with low pressure ECCS pump starting if the first indication of a LOCA is high drywell pressure). This Function is only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events, (i.e., non-DBA recirculation system pipe breaks or other RPV pipe breaks), the success of the Loop Select Logic is less critical than for the DBA.

LPCI Loop Select Reactor Vessel Water Level - Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water (variable leg) in the vessel.

The LPCI Loop Select Reactor Vessel Water Level - Low Low Allowable Value is chosen to be slightly higher than the level that starts the low pressure ECCS pumps so that certain actions associated with the LPCI function are accomplished in time to effect rapid core reflooding when vessel level is dropping rapidly, i.e., during a DBA LOCA.

Four channels of LPCI Loop Select Reactor Vessel Water Level - Low Low Function are only required to be OPERABLE in Modes 1, 2, and 3 to ensure that no single failure can preclude LPCI Loop Select Logic initiation. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the LPCI System is considered to consist of two independent subsystems (Refer to BASES for LCO 3.5.2).

2.h LPCI Loop Select - Reactor Steam Dome Pressure - Low

The purpose of the LPCI Loop Select Reactor Steam Dome Pressure - Low Function is to optimize the LPCI Loop Select Logic sensitivity if the logic previously actuated

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.h LPCI Loop Select - Reactor Steam Dome Pressure – Low (continued)

recirculation pump trips. This is accomplished by preventing the logic from continuing on to the unbroken loop selection activity until reactor steam dome pressure has dropped below a specified value. This Function is only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events, (i.e., non-DBA recirculation system pipe breaks), or other RPV pipe breaks the success of the Loop Select Logic is less critical than for the DBA.

LPCI Loop Select Reactor Steam Dome Pressure - Low signals are initiated from four pressure switches that sense the reactor steam dome pressure.

The Allowable Value is chosen to optimize the sensitivity of the portion of the LPCI Loop Select Logic that selects the unbroken recirculation loop for LPCI injection, while ensuring that LPCI injection is not unnecessarily delayed.

Four channels of LPCI Loop Select Reactor Steam Dome Pressure - Low Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully selecting the unbroken recirculation loop for LPCI injection. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the LPCI System is considered to consist of two independent subsystems (Refer to BASES for LCO 3.5.2).

2.i. LPCI Loop Select - Recirculation Pump Differential Pressure

Recirculation Pump Differential Pressure signals are used by the LPCI Loop Select Logic to determine if either recirculation pump is running. If either pump is not running, i.e., Single Loop Operation, the logic sends a trip signal to both recirculation pumps. This is necessary to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.i. LPCI Loop Select - Recirculation Pump Differential Pressure (continued)

eliminate the possibility of small pipe breaks being masked by a running recirculation pump. This Function is only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events (i.e., non-DBA recirculation system pipe breaks or other RPV pipe breaks), the success of the Loop Select Logic is less critical than for the DBA.

LPCI Loop Select Recirculation Pump Differential Pressure signals are initiated from eight differential pressure switches, four of which sense the pressure differential between the suction and discharge of each recirculation pump.

The Allowable Value is chosen to be as low as possible, while still maintaining the ability to differentiate between a running and non-running recirculation pump.

Eight channels of LPCI Loop Select - Recirculation Pump Differential Pressure Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully determining if either recirculation pump is running. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the LPCI System is considered to consist of two independent subsystems. (Refer to BASES for LCO 3.5.2).

2.j. LPCI Loop Select - Recirculation Riser Differential Pressure

Recirculation Riser Differential Pressure signals are used by the LPCI Loop Select Logic to determine which, if any, recirculation loop is broken. This is accomplished by comparing the absolute pressure of the two recirculation loops. A broken loop will be indicated by a lower pressure

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.j. LPCI Loop Select - Recirculation Riser Differential Pressure (continued)

than an unbroken loop. The loop with the higher pressure is then selected for LPCI injection. If neither loop is broken, the logic defaults to injecting into the "B" recirculation loop. This Function is only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events, (i.e., non-DBA recirculation system pipe breaks), or other RPV pipe breaks, the success of the Loop Select Logic is less critical than for the DBA.

LPCI Loop Select Recirculation Riser Differential Pressure signals are initiated from four differential pressure transmitters/alarm units that sense the pressure differential between the A recirculation loop riser and the B recirculation loop riser. If, after a small time delay, the pressure in loop A is not indicating higher than loop B pressure, the logic will select the B loop for injection. If recirculation loop A pressure is indicating higher than loop B pressure, the logic will select the A loop for LPCI injection.

The Allowable Value is chosen to be as low as possible, while still maintaining the ability to differentiate between a broken and unbroken recirculation loop.

Four channels of LPCI Loop Select Recirculation Riser Differential Pressure Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully selecting the unbroken recirculation loop for LPCI injection. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the LPCI System is considered to consist of two independent subsystems. (Refer to BASES for LCO 3.5.2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

HPCI System

3.a. Reactor Vessel Water Level - Low Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCI System is initiated at Reactor Vessel Water Level - Low Low to maintain level above the top of the active fuel. Reactor Vessel Water Level - Low Low is one of the Functions assumed to be OPERABLE and capable of initiating HPCI during the transients analyzed in References 3 and 4. Additionally, the Reactor Vessel Water Level - Low Low Function associated with HPCI is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level — Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — Low Low Allowable Value is high enough such that for a small break LOCA, the HPCI System will be sufficient to avoid initiation of the ADS System at Reactor Vessel Water Level — Low Low Low.

Four channels of Reactor Vessel Water Level — Low Low Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI initiation. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.b. Drywell Pressure — High

High pressure in the drywell could indicate a break in the RCPB. The HPCI System is initiated upon receipt of the Drywell Pressure — High Function in order to minimize the possibility of fuel damage. The Drywell Pressure — High Function, along with the Reactor Water Level — Low Low Function, is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. Drywell Pressure - High (continued)

function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure switches that sense drywell pressure. The Allowable Value was selected to be as low as possible to be indicative of a LOCA inside primary containment.

Four channels of the Drywell Pressure — High Function are required to be OPERABLE when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI initiation. Refer to LCO 3.5.1 for the Applicability Bases for the HPCI System.

3.c. Reactor Vessel Water Level — High

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Reactor Vessel Water Level - High signal is used to trip the HPCI turbine to prevent overflow into the Main Steam Lines (MSLs). The Reactor Vessel Water Level — High Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk, thus it meets Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Reactor Vessel Water Level — High signals for HPCI are initiated from two level switches. Both Reactor Vessel Water Level - High signals are required in order to trip the HPCI turbine. This ensures that no single instrument failure can preclude HPCI initiation. The Reactor Vessel Water Level — High Allowable Value is chosen to prevent flow from the HPCI System from overflowing into the MSLs.

Two channels of Reactor Vessel Water Level — High Function are required to be OPERABLE only when HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.d. Condensate Storage Tank Level — Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this preferred source. Normally the suction valves between HPCI and the CST are open and, upon receiving a HPCI initiation signal, water for HPCI injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water from a safety related source is available to the HPCI pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Condensate Storage Tank Level — Low signals are initiated from two level switches. The logic is arranged such that either level switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Condensate Storage Tank Level — Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST.

Two channels of the Condensate Storage Tank Level — Low Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI suction transfer to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.e. Suppression Pool Water Level — High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e. Suppression Pool Water Level — High (continued)

interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes. This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Suppression Pool Water Level — High signals are initiated from two level switches. The logic is arranged such that either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Allowable Value for the Suppression Pool Water Level — High Function is chosen to ensure that HPCI will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level — High Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI suction transfer to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.f. High Pressure Coolant Injection Pump Discharge Flow — Low (Bypass)

The minimum flow instruments are provided to protect the HPCI pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The High Pressure Coolant Injection Pump Discharge Flow — Low Function is assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents analyzed in References 2, 3 and 4 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch is used to detect the HPCI System's flow rate. The logic is arranged such that the switch causes the minimum flow valve to open if flow is low and pump discharge

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILTY

3.f High Pressure Coolant Injection Pump Discharge Flow - Low (Bypass) (continued)

pressure is above a specified valve. The logic will close the minimum flow valve once the flow rate closure setpoint is exceeded. The High Pressure Coolant Injection Pump Discharge Flow — Low Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow the assumed flow into the core.

One channel is required to be OPERABLE when HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level — Low Low Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this Function. The Reactor Vessel Water Level — Low Low Low is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accident analyzed in Reference 2. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level — Low Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Low Low Function are required to be OPERABLE only when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two channels input to ADS trip logic A, while the other two channels input to ADS trip logic B. Refer to LCO 3.5.1 for ADS Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a, 5.a. Reactor Vessel Water Level — Low Low Low (continued)

The Reactor Vessel Water Level — Low Low Low Allowable Value is chosen to allow time for the low pressure core flooding systems to initiate and provide adequate cooling.

4.b, 5.b. Automatic Depressurization System Timer

The purpose of the Automatic Depressurization System Timer is to delay depressurization of the reactor vessel to allow the HPCI System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCI System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the timer, or to inhibit initiation permanently. The Automatic Depressurization System Timer Function is assumed to be OPERABLE for the accident analyses of Reference 2 that require ECCS initiation and assume failure of the HPCI System.

There are two Automatic Depressurization System Timer relays, one in each of the two ADS trip logics. The Allowable Value for the Automatic Depressurization System Timer is based upon a nominal setting of 2 minutes with an allowance for drift. The nominal setting of 2 minutes is chosen so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

Two channels of the Automatic Depressurization System Timer Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip logic A, while the other channel inputs to ADS trip logic B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.c, 5.c. Reactor Vessel Water Level - Low (Confirmatory)

The Reactor Vessel Water Level - Low Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.c, 5.c. Reactor Vessel Water Level - Low (Confirmatory) (continued)

Reactor Vessel Water Level - Low Low Low signals. In order to prevent spurious initiation of the ADS due to a single instrument line break, a Reactor Vessel Water Level - Low signal must also be received before ADS initiation commences.

Reactor Vessel Water Level - Low signals are initiated from two level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Allowable Value for Reactor Vessel Water Level - Low is selected at the RPS Reactor Vessel Water Level - Low scram Allowable Value for convenience. Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for the Bases discussion of this Function.

Two channels of Reactor Vessel Water Level — Low Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. One channel inputs to ADS trip logic system A, while the other channel inputs to ADS trip logic B. Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d, 5.e. Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure — High

The Pump Discharge Pressure □ High signals from the CS and LPCI pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure □ High is one of the Functions assumed to be OPERABLE and capable of permitting ADS initiation during the events analyzed in Reference 2 with an assumed HPCI failure. For these events the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Pump discharge pressure signals are initiated from twelve pressure switches, two on the discharge side of each of the six low pressure ECCS pumps. In order to generate an ADS permissive in one trip logic, it is necessary that one of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.d, 4.e, 5.d, 5.e. Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure — High (continued)

the channels from the discharge of the three low pressure ECCS pumps in the same division indicate high discharge pressure, and one of the redundant channels from the same three pumps also indicate high discharge pressure (i.e, one-out-of three taken twice). The Pump Discharge Pressure —High Allowable Value is less than the pump discharge pressure when one pump is operating in minimum bypass flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the CS and LPCI pumps are aligned for injection and the pumps are not running. The actual operating point of this function is not assumed in any transient or accident analysis.

Twelve channels of Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure — High Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two CS channels associated with CS pump A and four LPCI channels associated with LPCI pumps A and C are required for trip logic A. Two CS channels associated with CS pump B and four LPCI channels associated with LPCI pumps B and D are required for trip logic B. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

(continued)

BASES

ACTIONS (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.1-1. The applicable Condition referenced in the table is Function dependent. Each time a channel is discovered inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1, B.2, and B.3

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic initiation capability being lost for the feature(s). Required Action B.1 features would be those that are initiated by Functions 1.a, 1.b, 2.a, and 2.b (e.g., low pressure ECCS). The Required Action B.2 system would be HPCI. For Required Action B.1, redundant automatic initiation capability is lost if certain combinations of two or more Function 1.a, 1.b, 2.a or 2.b channels are inoperable and untripped in more than one trip system. Since there are three redundant low pressure ECCS subsystems (i.e., CS 'A', CS 'B', and the LPCI subsystem), Required Action B.1 is only applicable if initiation capability is lost in either: 1) both CS subsystems, or 2) either of the CS subsystems and the LPCI subsystem. For low pressure ECCS, since each inoperable channel would have Required Action B.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated system of low pressure ECCS and DGs to be declared inoperable. However, since channels that provide input to initiation logics associated with two or more low pressure ECCS subsystems (i.e., both CS subsystems or either CS subsystem in combination with the LPCI subsystem) are inoperable and untripped, and the Completion Times started concurrently for the channels associated with two or more low pressure ECCS subsystems, this results in the affected portions in the associated low pressure ECCS and DGs being concurrently declared inoperable.

(continued)

BASES

ACTIONS

B.1, B.2 and B.3 (continued)

For Required Action B.2, automatic initiation capability is lost if certain combinations of Function 3.a or Function 3.b channels are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.3 is not appropriate and the feature(s) associated with the inoperable, untripped channels must be declared inoperable within 1 hour.

Notes are provided (the Note to Required Action B.1 and the Note to Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed. Required Action B.1 (the Required Action for certain inoperable channels in the low pressure ECCS subsystems) is not applicable to Function 2.d, since this Function provides backup to administrative controls ensuring that operators do not divert LPCI flow from injecting into the core when needed. Thus, a total loss of Function 2.d capability for 24 hours is allowed, since the LPCI System remains capable of performing its intended function.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in two or more low pressure ECCS subsystems (i.e., both CS subsystems or either CS subsystem in combination with the LPCI subsystem) cannot automatically initiate their supported features due to inoperable, untripped channels within the same Function as described in the paragraph above.

(continued)

BASES

ACTIONS

B.1, B.2 and B.3 (continued)

For Required Action B.2, the Completion Time only begins upon discovery that the HPCI System cannot be automatically initiated due to the required combination of two inoperable, untripped channels for the associated Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition I must be entered and its Required Action taken.

C.1, C.2 and C.3

Required Actions C.1 and C.2 are intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function result in automatic initiation capability being lost for redundant features either in both divisions of LPCI Loop Select Logic or in two or more low pressure ECCS subsystems. Required Action C.1 features would be those that are initiated by Functions 1.c, 2.c, 1.e, and 2.e (i.e., low pressure ECCS). Required Action C.2 would be the feature affected by Functions 2.g, 2.h, 2.i, and 2.j (i.e., the LPCI Loop Select Logic). Redundant automatic initiation capability is lost if certain combinations of either (a) two Function 1.c or 2.c channels are inoperable in two or more low pressure ECCS trip systems, (b) two Function 2.g channels are inoperable in both trip systems, (c) two Function 2.h channels are inoperable in both trip systems,

(continued)

BASES

ACTIONS

C.1, C.2 and C.3 (continued)

(d) two or more Function 2.i channels for the same recirculation pump are inoperable in both trip systems, (e) two Function 2.j channels are inoperable in both trip systems, or (f) two or more Function 1.e or 2.e channels are inoperable in different divisions. In these situations (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.3 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour. Since each inoperable channel would have Required Action C.1 or C.2, as appropriate, applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated system to be declared inoperable. However, since channels for either both divisions of LPCI loop select logic or for two or more low pressure ECCS subsystems are inoperable (e.g., both CS subsystems or either CS subsystem in combination with the LPCI subsystem), and the Completion Times started concurrently for the channels in both subsystems, this results in the affected portions in both subsystems being concurrently declared inoperable. For Functions 1.c, 1.e, and 2.e, the affected portions are the associated low pressure ECCS pumps. For Functions 2.g, 2.h, 2.i, and 2.j, the affected portion is the LPCI subsystem.

The Note to Required Action C.1 states that Required Action C.1 is only applicable for Functions 1.c, 2.c, 1.e, and 2.e. The Note to Required Action C.2 states that Required Action C.2 is only applicable for Functions 2.g, 2.h, 2.i, and 2.j. Required Actions C.1 and C.2 are not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss of the Function (two-out-of-two logic). This loss was considered during the development of Reference 5 and considered acceptable for the 24 hours allowed by Required Action C.3.

(continued)

BASES

ACTIONS

C.1, C.2 and C.3 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." For Required Actions C.1 and C.2, the Completion Time only begins upon discovery that the same feature, either in both divisions of LPCI Loop Select Logic or in two or more low pressure ECCS subsystems, cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition I must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic suction transfer capability for the HPCI System. Automatic suction transfer capability is lost if two Function 3.d channels or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI suction transfer capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

(continued)

BASES

ACTIONS

D.1, D.2.1 and D.2.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of suction transfer capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCI suction piping), Condition I must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the Core Spray and Low Pressure Coolant Injection Pump Discharge Flow — Low Bypass Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.d and 2.f (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if either the automatic opening or closing function for two or more low pressure ECCS minimum flow valves is inoperable. Since each of the four minimum flow valves is initiated by a corresponding instrument channel, redundant automatic initiation capability is lost if any two of the four Function 1.d and 2.f channels are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump(s) to be declared inoperable. However, since channels for two or more minimum flow valves in the low pressure ECCS subsystems are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS minimum flow valves, this results in the affected low pressure ECCS pump(s) being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the system or subsystem associated with each inoperable channel must be declared inoperable within 1 hour. A Note is also provided (the Note to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCI Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 5 and considered acceptable for the 7 days allowed by Required Action E.2.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock."

For Required Action E.1, the Completion Time only begins upon discovery that redundant automatic initiation capability for two or more low pressure ECCS minimum flow valves is inoperable due to inoperable channels as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable, such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation, such that the valve would not automatically close, a portion of the subsystem flow could be diverted from the reactor vessel injection path, causing insufficient core cooling. These consequences can be averted by the operator's manual control of the valve, which would be adequate to maintain ECCS pump protection and required flow. However, remote manual valve control can only be accomplished with temporary logic modifications during this period. Furthermore, other ECCS pumps would be sufficient to complete the assumed safety function if no additional single failure were to occur. The 7 day Completion Time of Required Action E.2 to restore the inoperable channel to OPERABLE status is reasonable based on the remaining capability of the associated ECCS subsystems, the redundancy available in the ECCS design, and the low probability of a DBA occurring during the allowed out of service time. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition I must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

(continued)

BASES

ACTIONS (continued)

F.1

With a Function 1.f (2.k) channel inoperable, the 4.16 kV Emergency Bus Sequential Loading Relay is not cable of providing a start permissive signal for the low pressure ECCS pumps in the affected division, and the associated low pressure ECCS are not capable of performing their intended functions. Placing a channel in the tripped condition makes the associated ECCS pump(s) inoperable, since the pump(s) is prevented from automatically starting. In fact, tripping the bus power monitor relay will cause the associated DG to start, as it is common to the bus undervoltage logic. Consequently, one hour is provided to restore OPERABILITY of the channel. Otherwise, the affected low pressure ECCS subystems are declared inoperable immediately. This requires entry into LCO 3.5.1, which provides appropriate actions for inoperable low pressure ECCS Systems and subsystems.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip logic A and B Functions result in redundant automatic initiation capability being lost for the ADS. Redundant automatic initiation capability is lost if either (a) one Function 4.a channel and one Function 5.a channel are inoperable and untripped, or (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock."

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE. If either HPCI or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action G.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition I must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

H.1 and H.2

Required Action H.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable or (b) a combination of Function 4.d, 4.e, 5.d, and 5.e channels are inoperable such that both channels associated with three low pressure ECCS pumps in the same division are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action H.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." For Required Action H.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE (Required Action H.2). If either HPCI or RCIC is inoperable, the time shortens to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

service time, Condition I must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

I.1

With any Required Action and associated Completion Time not met, the associated feature(s) may be incapable of performing the intended function, and the supported feature(s) associated with inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 1.d, 2.f, 3.c, 3.d, 3.e, and 3.f; and (b) for up to 6 hours for Functions other than 1.d, 2.f, 3.c, 3.d, 3.e, and 3.f provided the associated Function (or redundant Function in the case of ADS Logics A and B) maintains ECCS initiation or loop selection capability. Loop selection capability is maintained so long as sufficient channels are OPERABLE for the Loop Select Logic to be able to identify the intact recirculation loop for injection. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ECCS will initiate when necessary.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

Because the Ref. 5 analysis made no assumptions regarding the elapsed time between testing of consecutive channels in the same logic, it is not necessary to remove jumpers/relays blocks or reconnect lifted leads used to prevent actuation of the trip logic during testing of logic channels with instruments in series solely for the purpose of administering the AOT clocks, provided that the AOT allowance is not exceeded on a per instrument channel basis.

SR 3.3.5.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited in time; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.1.2, SR 3.3.5.1.3, and SR 3.3.5.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.2, SR 3.3.5.1.3, and SR 3.3.5.1.5 (continued)

of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency for SR 3.3.5.1.3 is based on the reliability analyses of Reference 5.

The Surveillance Frequencies of SR 3.3.5.1.2 and SR 3.3.5.1.5 are based upon engineering judgment and the reliability of the components.

The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

SR 3.3.5.1.4, SR 3.3.5.1.6, SR 3.3.5.1.7, and SR 3.3.5.1.8

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program. The Frequency is based upon the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.9

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 5.4.7.

2. UFSAR, Section 6.3.2.

3. UFSAR, Chapter 15.

4. NEDC-32980P, "Safety Analysis Report for Duane Arnold Energy Center Extended Power Uprate," Rev. 1, April 2001.

5. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control Instrumentation

BASES

BACKGROUND

The RPV contains penetrations below the TS 2.1.1.3 Safety Limit that have the potential to drain the reactor coolant inventory to below the TS 2.1.1.3 Safety Limit. If the water level should drop below the TS 2.1.1.3 Safety Limit, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in MODES 1, 2, and 3 in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," or LCO 3.3.6.1, "Primary Containment Isolation Instrumentation".

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TS 2.1.1.3

(continued)

BASES

BACKGROUND (continued)

Safety Limit when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control,” and the definition of DRAIN TIME. There are functions that are required for manual initiation or operation of the ECCS injection/spray subsystem required to be OPERABLE by LCO 3.5.2 and other functions that support automatic isolation of Residual Heat Removal subsystem and Reactor Water Cleanup system penetration flow path(s) on low RPV water level.

The RPV Water Inventory Control Instrumentation supports operation of core spray (CS) and low pressure coolant injection (LPCI). The equipment involved with each of these systems is described in the Bases for LCO 3.5.2.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect and Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulated in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is postulated in which a single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error). It is assumed, based on engineering judgment, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Steam Dome Pressure - Low (Injection Permissive)

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. This function ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. While it is assured during MODES 4 and 5 that the reactor steam dome pressure will be below the ECCS maximum design pressure, the Reactor Steam Dome Pressure - Low signals are assumed to be OPERABLE and capable of permitting initiation of the ECCS.

The Reactor Steam Dome Pressure - Low signals are initiated from four pressure switches that sense the reactor dome pressure. The pressure switches are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic.

The Allowable Value is low enough to prevent overpressuring the equipment in the low pressure ECCS.

The four channels of Reactor Steam Dome Pressure – Low Function are required to be OPERABLE in MODES 4 and 5.

1.b, 2.b. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valve is opened when low flow is

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b, 2.b. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass) (continued)

sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump.

One flow transmitter for each Core Spray subsystem and each LPCI subsystem is used to detect the associated subsystems' flow rates. The logic is arranged such that each transmitter causes its associated minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the Residual Heat Removal (RHR) shutdown cooling mode.

The Pump Discharge Flow - Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

One channel of the Pump Discharge Flow - Low Function is required to be OPERABLE in MODES 4 and 5 when the associated Core Spray or LPCI pump is required to be OPERABLE by LCO 3.5.2 to ensure the subsystem is capable of injecting into the Reactor Pressure Vessel when manually initiated.

RHR System Isolation

3.a - Reactor Vessel Water Level – Low

The definition of Drain Time allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TS 2.1.1.3 Safety Limit when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

The Reactor Vessel Water Level — Low signals are initiated from four level indicating switches that sense the difference between the pressure due to a constant column of water (reference leg) and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a - Reactor Vessel Water Level – Low (continued)

the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level – Low Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low Allowable Value (LCO 3.3.6.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME.

This Function isolates the Group 4 valves.

Reactor Water Cleanup (RWCU) System Isolation

4.a - Reactor Vessel Water level – Low Low

The definition of Drain Time allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TS 2.1.1.3 Safety Limit when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low Low Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

Reactor Vessel Water Level - Low Low signals are initiated from four level indicating switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level – Low Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level – Low Low Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a - Reactor Vessel Water level – Low Low (continued)

The Reactor Vessel Water Level – Low Low Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME.

This Function isolates Group 5 valves.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPV Water Inventory Control instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable RPV Water Inventory Control instrumentation channel.

(continued)

BASES

ACTIONS (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.2-1. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

RHR System Isolation, Reactor Vessel Water Level - Low and Reactor Water Cleanup System, Reactor Vessel Water Level - Low Low functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating Drain Time. If the instrumentation is inoperable, Required Action B.1 directs an immediate declaration that the associated penetration flow path(s) are incapable of automatic isolation. Required Action B.2 directs calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

C.1

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. If the permissive is inoperable, manual initiation of ECCS is prohibited. Therefore, the permissive must be placed in the trip condition within 1 hour. With the permissive in the trip condition, manual initiation may be performed.

The Completion Time of 1 hour is intended to allow the operator time to evaluate any discovered inoperabilities and to place the channel in trip.

D.1

If a Core Spray or Low Pressure Coolant Injection Pump Discharge Flow – Low bypass function is inoperable, there is a risk that the associated low pressure ECCS pump could overheat when the pump is operating and the associated injection valve is not fully open. In this condition, the operator can take manual control of the pump and the injection valve to ensure the pump does not overheat.

The 24 hour Completion Time was chosen to allow time for the operator to evaluate and repair any discovered inoperabilities.

(continued)

BASES

ACTIONS

D.1 (continued)

The Completion Time is appropriate given the ability to manually start the ECCS pumps and open the injection valves and to manually ensure the pump does not overheat.

E.1

With the Required Action and associated Completion Time of Condition C or D not met, the associated low pressure ECCS injection/spray subsystem may be incapable of performing the intended function, and must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.2-1.

SR 3.3.5.2.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.2 (continued)

Any setpoint adjustment chall be consistent with the assumptions of the current plant specific methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, “Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves,” August 1986.

3. Generic Letter 92-04, “Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(F),” August 1992.

4. NRC Bulletin 93-03, “Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs,” May 1993.

5. Information Notice 94-52, “Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1,” July 1994.

B 3.3 INSTRUMENTATION

B 3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is unavailable, such that initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

The RCIC System may be initiated by either automatic or manual means, although manual initiation requires manipulation of individual component control switches. Automatic initiation occurs for conditions of reactor vessel low low water level. The variable is monitored by four level switches that are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic arrangement. Once initiated, the RCIC logic seals in and can be reset by the operator only when the reactor vessel water level signals have cleared.

The RCIC test return valve is closed on a RCIC initiation signal to allow full system flow to the Reactor Pressure Vessel (RPV). However, this design feature is not assumed in any transient analyses. Transient analyses are performed assuming the RCIC System is in the standby readiness condition when the transient occurs.

The RCIC System also monitors the water levels in the Condensate Storage Tank (CST) since this is the preferred source of water for RCIC operation. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction from the suppression pool valves is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in the CST. Either switch can cause the suppression pool suction valves to open and the CST suction valve to close (i.e., one-out-of-two once logic).

(continued)

BASES

BACKGROUND (continued)

To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the RPV high water level trip (two-out-of-two once logic), at which time the RCIC steam supply valve closes (the injection valve also closes due to the closure of the steam supply valve). The RCIC System restarts if vessel level again drops to the low low level initiation point.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The function of the RCIC System, to provide makeup coolant to the reactor, is used to respond to transient events. The RCIC System is not an ECCS System, although the RCIC System Operation is credited during Loss of Feedwater events. Based on its contribution to the reduction of overall plant risk, however, the system, and therefore its instrumentation meets Criterion 4 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RCIC System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.3-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RCIC System instrumentation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip Setpoints are those predetermined values of output at which an action should take place.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor, bi-stable trip circuit, or trip unit) changes state. Margin is provided to allow for process, calibration (i.e., M&TE) and some instrument uncertainties (e.g., drift). Allowable Values derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The individual Functions are required to be OPERABLE in MODE 1, and in MODES 2 and 3 with reactor steam dome pressure > 150 psig since this is when RCIC is required to be OPERABLE. (Refer to LCO 3.5.3 for Applicability Bases for the RCIC System.)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Vessel Water Level — Low Low

Low RPV water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Reactor Vessel Water Level - Low Low to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level — Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — Low Low Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with the High Pressure Coolant Injection assumed to fail will be sufficient to maintain adequate core cooling. However, the prevention of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level — Low Low (continued)

initiation of low pressure ECCS at Reactor Vessel Water Level - Low Low Low is not assured.

Four channels of Reactor Vessel Water Level — Low Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2. Reactor Vessel Water Level — High

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Reactor Vessel Water Level - High signal is used to close the RCIC steam supply valve to prevent overflow into the Main Steam Lines (MSLs). (The injection valve also closes due to the closure of the steam supply valve.)

Reactor Vessel Water Level — High signals for RCIC are initiated from two level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — High Allowable Value is high enough to preclude isolating the injection valve of the RCIC during normal operation, yet low enough to trip the RCIC System prior to water overflowing into the MSLs.

Two channels of Reactor Vessel Water Level — High Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3. Condensate Storage Tank Level — Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this preferred source. Normally, the suction valve between the RCIC pump and the CST is open and, upon receiving a RCIC initiation signal,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Condensate Storage Tank Level — Low (continued)

water for RCIC injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes.

Two level switches are used to detect low water level in the CSTs. The Condensate Storage Tank Level — Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CST.

Two channels of Condensate Storage Tank Level — Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to RCIC System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RCIC System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, the Note has been provided to allow separate Condition entry for each inoperable RCIC System instrumentation channel.

(continued)

BASES

ACTIONS (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.3-1. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this case, automatic initiation capability is lost if certain combinations of two Function 1 channels are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock". For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to the required combination of two inoperable, untripped Reactor Vessel Water Level — Low Low channels. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level — High Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC shutdown on high level capability. As stated above, this loss of automatic RCIC shutdown capability was analyzed and determined to be acceptable.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic suction transfer capability being lost. The automatic suction transfer capability is lost if two Function 3 channels are inoperable and untripped. In this situation (loss of automatic suction transfer), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC suction transfer capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of suction transfer capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide suction transfer signals and the fact that the RCIC System is not assumed in any accident analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC discharge piping), Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 2 and 3; and (b) for up to 6 hours for Function 1, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 1) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary. Because the Ref. 1 analysis made no assumptions regarding the elapsed time between testing of consecutive channels in the same logic, it is not necessary to remove jumpers/relay blocks or reconnect lifted leads used to prevent actuation of the trip logic during testing of logic channels with instruments in series solely for the purpose of administering the AOT clocks, provided that the AOT allowance is not exceeded on a per instrument channel basis.

SR 3.3.5.3.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a parameter on other similar channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.3.1 (continued)

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the reliability analysis of Reference 1.

SR 3.3.5.3.3 and SR 3.3.5.3.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. GENE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

The primary containment isolation instrumentation automatically initiates closure of appropriate Primary Containment Isolation Valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Primary 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 DBA.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and Reactor Coolant Pressure Boundary (RCPB) isolation. Most channels include equipment (e.g., on-off sensors or bi-stable trip circuits) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logics are (a) reactor vessel water level, (b) area ambient and differential temperatures, (c) Main Steam Line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum, (f) main steam line pressure, (g) High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) steam line flow, (h) drywell pressure, (i) HPCI and RCIC steam line pressure, (j) HPCI and RCIC turbine exhaust diaphragm pressure, (k) Reactor Water Cleanup (RWCU) differential flow, (l) reactor steam dome pressure, (m) Offgas Vent Stack radiation, (n) Reactor Building Exhaust Shaft radiation, and (o) Refueling Floor Exhaust Duct radiation. Redundant sensor input signals from each parameter are provided for automatic initiation of isolation. The only exceptions are SLC System initiation and RWCU differential flow. In addition, manual isolation of certain logics is provided. Primary containment isolation instrumentation has inputs to the trip logic of the isolation functions listed below.

(continued)

BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

Most MSL Isolation Functions receive inputs from four channels. The outputs from these channels are combined in a one-out-of-two taken twice logic to initiate isolation of all Main Steam Isolation Valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate both MSL drain valves. Both trip systems receive inputs from both Divisions of instrument channels (e.g., channels A1 and B1 or channels A2 and B2). The MSL drain line has two isolation valves with one two-out-of-two logic system associated with each valve.

The exceptions to this arrangement are the Main Steam Line Flow - High Function and Area Temperature Functions. The Main Steam Line Flow — High Function uses 16 flow channels, four for each steam line. Because of the number of instrument channels, they are arranged in a unique manner to achieve both electrical and spatial separation. One instrument channel from each steam line inputs to one of the four logic channels. Two logic channels make up each trip system and both trip systems must trip to cause an MSL isolation. Each logic channel has four inputs (one per MSL), any one of which will trip the logic channel. The logic channels are arranged in a one-out-of-two taken twice logic trip system. This allows one logic channel to be out of service and still provide isolation capability in the event of a steam line break in any MSL. This is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one-out-of-four twice logic), with each trip system isolating one of the two MSL drain valves.

The Main Steam Tunnel Temperature — High Function receives input from 16 channels. Because of the number of instrument channels, they are arranged in a unique manner to achieve both electrical and spatial separation. The logic is arranged similar to the Main Steam Line Flow — High Function, except that the four channels from each steam line input to one of the four logic channels. The Turbine Building Area Temperature — High Function receives input from 8 channels. The inputs are arranged in a one-out-of-four taken twice logic trip system to isolate all MSIVs. Similarly, the inputs are arranged in two one-out-of-two twice logic trip

(continued)

BASES

BACKGROUND 1. Main Steam Line Isolation (continued)

systems, with each trip system isolating one of the two MSL drain valves.

MSL Isolation Functions isolate the Group 1 valves.

2. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from four channels. The outputs from these channels are arranged into two two-out-of-two logic trip systems. Both trip systems receive inputs from both Divisions of instrument channels (e.g., channels A1 and B1 or channels A2 and B2). One trip system initiates isolation of all inboard primary containment isolation valves, while the other trip system initiates isolation of all outboard primary containment isolation valves. Each logic closes one of the two valves on each penetration, so that operation of either logic isolates the penetration.

An exception to this arrangement is the Offgas Vent Stack High-Radiation Function. This Function has two channels, whose outputs are arranged in two one-out-of-one logic trip systems. Each trip system isolates one valve per associated penetration, similar to the two-out-of-two logic described above.

Primary Containment Isolation Drywell Pressure — High and Reactor Vessel Water Level — Low Functions isolate the Group 2, 3, and 4 valves. Reactor Building Exhaust Shaft and Refueling Floor Exhaust Duct High-Radiation Functions isolate the Group 3 valves. Offgas Vent Stack High-Radiation Function isolates the containment purge and vent valves.

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation

Most Functions that isolate HPCI and RCIC receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems in each isolation group is connected to one of the two valves on each associated penetration.

(continued)

BASES

BACKGROUND

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation (continued)

The exceptions are the HPCI and RCIC Turbine Exhaust Diaphragm Pressure — High and Steam Supply Line Pressure — Low Functions. These Functions receive inputs from four turbine exhaust diaphragm pressure and four steam supply pressure channels for each system. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two two-out-of-two trip systems. Each trip system isolates one valve per associated penetration.

HPCI and RCIC Functions isolate the Group 6A, 6B, and 9 valves.

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level — Low Low Isolation Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. Both trip systems receive inputs from both Divisions of instrument channels (e.g., channels A1 and B1 or channels A2 and B2). The Differential Flow — High and SLC System Initiation Functions receive input from one channel. SLC System initiation only inputs to the outboard trip system using a one-out-of-one logic. Differential Flow - High also uses a one-out-of-one logic but inputs to both trip systems via separate relays. The Area Temperature — High Function receives input from six temperature monitors, three to each trip system. The Area Ventilation Differential Temperature — High Function receives input from six differential temperature monitors, three in each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to either an inboard valve or an outboard valve on each RWCU penetration.

RWCU Functions isolate the Group 5 valves.

6. Shutdown Cooling System Isolation

The Reactor Vessel Water Level — Low Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two two-out-of-two trip systems. Both trip systems receive inputs from both Divisions of instrument channels (e.g., channels

(continued)

BASES

BACKGROUND 6. Shutdown Cooling System Isolation (continued)

A1 and B1 or channels A2 and B2). The Drywell Pressure - High Function receives input from four drywell pressure channels. The outputs from the drywell pressure channels are connected to two two-out- of-two trip systems. The Reactor Steam Dome Pressure - High Function receives input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems is connected to one of the two shutdown cooling suction valves. In addition, one trip system isolates one LPCI inboard injection valve, while the other trip system isolates the other LPCI inboard injection valve (the inboard LPCI injection valves automatically close if either a Reactor Vessel Water Level - Low signal or a Drywell Pressure - High signal is received while both shutdown cooling suction valves are not fully closed).

Shutdown Cooling System Isolation Functions isolate the Group 4 valves.

7. Containment Cooling System Permissive

In order to initiate Containment Cooling with primary containment pressure greater than the high drywell pressure ECCS initiation signal, the containment cooling permissive logic must be satisfied (upon ECCS initiation, the containment cooling penetration isolation valves receive closing signals to ensure that all Low Pressure Coolant Injection (LCPI) System flow is directed to the reactor vessel, and to ensure that containment spray is automatically isolated at a primary containment pressure greater than the pressure assumed in the analysis used to show that the primary containment design negative pressure is not exceeded during the most rapid containment cooldown transient). The containment cooling permissive logic is satisfied if all of the following conditions exist; 1) Reactor Vessel Shroud level is greater than two thirds core height, 2) a LPCI initiation signal is present, and 3) primary containment pressure is greater than the Containment Pressure - High requirement. The first two conditions support LPCI System operation and are addressed in LCO 3.3.5.1, “ECCS Instrumentation”. The Containment Cooling System Permissive Function channels for the Containment Pressure - High signal receive inputs from different sensors than those that provide input to the Drywell Pressure - High ECCS initiation signals, and are addressed here.

(continued)

BASES

BACKGROUND

7. Containment Cooling System Permissive (continued)

The Containment Pressure - High Function receives input from four primary containment pressure channels. The outputs from the primary containment pressure channels are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. This common logic outputs into two trip systems for this function, one trip system is associated with one division of containment cooling and the other trip system is associated with the other division of containment cooling.

The Containment Cooling System Permissive Function allows the opening of the Drywell Spray, Suppression Pool Spray and Suppression Pool Cooling valves when the required conditions exist, and also results in an automatic isolation of those valves when containment pressure drops below the Containment Pressure - High setpoint.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary Containment Isolation Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Allowable Values are specified for each Primary Containment Isolation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor or bi-stable trip circuit) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

In general, the individual Functions are required to be OPERABLE in MODES 1, 2, and 3 consistent with the Applicability for LCO 3.6.1.1, "Primary Containment." Functions that have different Applicabilities are discussed below in the individual Functions discussion.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Main Steam Line Isolation

1.a. Reactor Vessel Water Level — Low Low Low

Low Reactor Pressure Vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level — Low Low Low Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level — Low Low Low Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 1). The isolation of the MSLs on Reactor Vessel Water Level - Low Low Low supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level — Low Low Low Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Low Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential Loss of Coolant Accident (LOCA) to prevent offsite doses from exceeding 10 CFR 50.67 limits.

This Function isolates the Group 1 valves.

1.b. Main Steam Line Pressure — Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure — Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 686 psig, which results in a scram due to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Main Steam Line Pressure — Low (continued)

MSIV closure, thus reducing reactor power to < 21.7% RTP.)

The MSL low pressure signals are initiated from four pressure switches that are each connected to an associated MSL. The pressure switches are arranged such that, even though physically separated from each other, each pressure switch is able to detect low MSL pressure. Four channels of Main Steam Line Pressure — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure — Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 2).

This Function isolates the Group 1 valves.

1.c. Main Steam Line Flow — High

Main Steam Line Flow — High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow — High Function is directly assumed in the analysis of the Main Steam Line Break (MSLB) (Ref. 8). The isolation action, along with the scram function of the Reactor Protection System (RPS) and the mass flow rate limiting function of the MSL flow restrictors, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 50.67 limits.

The MSL flow signals are initiated from 16 differential pressure switches that are connected to the four MSLs. The differential pressure switches are arranged such that, even though physically separated from each other, all four connected to one MSL would be able to detect the high flow. Four channels of Main Steam Line Flow — High Function for each unisolated MSL (two channels

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow - High (continued)

per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL. The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break. While expressed as a percentage of rated steam flow, the Allowable Value is actually displayed in terms of differential pressure across the MSL flow venturies, (i.e., psid).

This Function isolates the Group 1 valves.

1.d. Condenser Backpressure - High

The Condenser Backpressure - High Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Backpressure - High Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure (backpressure) signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Backpressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all Turbine Stop Valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

This Function isolates the Group 1 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.e and 1.f. Area Temperature — High

Area temperature is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the UFSAR, since bounding analyses are performed for large breaks, such as MSLBs.

Area temperature signals are initiated from Resistance Temperature Detectors (RTDs) located in the area being monitored. Sixteen channels of Main Steam Tunnel Temperature — High Function are available and 8 channels (2 per main steam line) are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function for a break of the size for which protection is necessary. Eight channels of Turbine Building Area Temperature — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Each channel consists of a RTD and its corresponding temperature monitor.

The Area Temperature-High Allowable Value is set far enough above the temperature expected during operations at rated power to avoid spurious isolation, yet low enough to provide early indication of a steamline break.

These Functions isolate the Group 1 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Primary Containment Isolation

2.a. Reactor Vessel Water Level — Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Reactor Vessel Water Level-Low supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Reactor Vessel Water Level — Low Function associated with isolation is implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level — Low signals are initiated from level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level — Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 2 and 3 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.b. Drywell Pressure — High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Drywell Pressure — High Function, associated with isolation of the primary containment, is implicitly assumed in the UFSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell Pressure — High per Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be approximately the same as the ECCS Drywell Pressure — High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 2 and 3 valves.

2.c. Offgas Vent Stack - High Radiation

High Offgas Vent Stack radiation indicates possible gross failure of the fuel cladding. Therefore, when Offgas Vent Stack High-Radiation is detected, an isolation is initiated to limit the release of fission products should a LOCA occur while the primary containment is undergoing vent or purge operations (Ref. 10). However, this Function is not assumed in any accident or transient analysis in the UFSAR because other leakage paths (e.g., MSIVs) are more limiting.

The offgas vent stack radiation signals are initiated from radiation detectors that are located in the offgas vent stack. Two channels of Offgas Vent Stack High-Radiation Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Offgas Vent Stack - High Radiation (continued)

The Allowable Value is low enough to ensure primary containment isolation prior to a maximum allowable 10 CFR 20 release, and is determined in accordance with the Offsite Dose Assessment Manual.

This Function is only required to isolate the containment vent and purge valves. This Function also starts the Standby Gas Treatment System.

2.d., 2.e. Reactor Building Exhaust Shaft and Refueling Floor Exhaust Duct - High Radiation

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When a Reactor Building Exhaust Shaft-High Radiation or Refueling Floor Exhaust Duct-High Radiation is detected, valves whose penetrations communicate with the primary containment atmosphere and certain other valves are isolated to limit the release of fission products. Additionally, the Refueling Floor Exhaust Duct High-Radiation Function is assumed to initiate isolation of the secondary containment during a fuel handling accident (Ref. 2).

These high radiation signals are initiated from radiation detectors that are located either in the reactor building exhaust shaft or in the exhaust duct coming from the refueling floor, respectively. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Exhaust Shaft — High Radiation Function and two channels of Refueling Floor Exhaust Duct — High Radiation Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

These Functions isolate the Group 3 valves. These Functions also start the Standby Gas Treatment System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Isolation

3.a., 4.a. HPCI and RCIC Steam Line Flow — High

Steam Line Flow — High Functions are provided to detect a break of the RCIC or HPCI steam lines and initiate closure of the steam line isolation valves of the appropriate system. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and the core can uncover. Therefore, the isolations are initiated on high flow to prevent or minimize core damage and to ensure that potential fission product releases are maintained within applicable limits. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for these Functions is not assumed in any UFSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC or HPCI steam line breaks from becoming bounding.

The HPCI and RCIC Steam Line Flow — High signals are initiated from differential pressure switches (two for HPCI and two for RCIC) that are connected to the system steam lines. Two channels of both HPCI and RCIC Steam Line Flow — High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

These Functions isolate the Group 6A and 6B valves, as appropriate.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.b., 4.b. HPCI and RCIC Steam Supply Line Pressure — Low

Low MSL pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. However, they also provide a diverse signal to indicate a possible system break and the HPCI Steam Supply Line Pressure - Low provides a permissive for the Drywell Pressure - High isolation of the HPCI and RCIC turbine exhaust vacuum breakers. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments (i.e., the measured variable failing low or the setpoint failing high) preventing HPCI and RCIC initiations (Ref. 3). Therefore, they meet Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The HPCI and RCIC Steam Supply Line Pressure — Low signals are initiated from pressure switches (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure — Low Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are selected to be high enough to prevent damage to the system's turbine. Also, the upper Allowable Value for HPCI Steam Supply Line Pressure-Low is selected to ensure HPCI is available in the pressure range assumed in the LOCA analysis.

These Functions isolate the Group 6A and 6B valves, as appropriate.

3.c., 4.c. HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High

High turbine exhaust diaphragm pressure indicates that the pressure may be too high to continue operation of the associated system's turbine. That is, the inner diaphragm has developed a leak and pressure is reaching a point where the outer diaphragm may be challenged. These isolations are for equipment and personnel safety protection and are not assumed in any transient or accident analysis in the UFSAR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.c., 4.c. HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High (continued)

These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 3). In addition, the failure of these instruments to detect a degraded inner diaphragm, increases the risk of an unwarranted release of steam to the equipment space. Therefore, they meet Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High signals are initiated from pressure switches (four for HPCI and four for RCIC) that are connected to the area between the rupture diaphragms on each system's turbine exhaust line. Four channels of both HPCI and RCIC Turbine Exhaust Diaphragm Pressure — High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are low enough to detect a degraded inner diaphragm to prevent extended operation with only the outer diaphragm acting as a system pressure boundary.

These Functions isolate the Group 6A and 6B valves, as appropriate.

3.d., 4.d. Drywell Pressure — High

High drywell pressure can indicate a break in the RCPB. The isolation of the HPCI and RCIC turbine exhaust vacuum breakers is provided to prevent communication with the suppression pool atmosphere when high primary containment pressure exists. A potential leakage path exists via the turbine exhaust line. The isolation is delayed until the system becomes unavailable for injection (i.e., low steam line pressure). The isolation of the HPCI and RCIC turbine exhaust vacuum breakers by Drywell Pressure - High is accomplished by common Motor Operated Valves (MOVs) in series, and is indirectly assumed in the UFSAR accident analysis because the turbine exhaust leakage path is not assumed to contribute to offsite doses. Following system shutdown after a LOCA, a closure of the MOVs results in suppression pool pressure forcing water to the turbine exhaust line check valves, thereby precluding gaseous outleakage through this path. The isolation logic ensures the availability of the vacuum breaker feature following HPCI or RCIC operation while at the same time providing the desired containment isolation capability following a LOCA (Ref. 7).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d., 4.d. Drywell Pressure-High (continued)

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Two channels of Drywell Pressure — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure — High Allowable Value (LCO 3.3.5.1), since this is indicative of a LOCA inside primary containment.

This Function isolates the Group 9 valves.

3.e., 3.g., 3.h., 3.i., 4.e., 4.g., 4.h., 4.i. Area and Differential Temperature — High

Area and differential temperatures are provided to detect a leak from the associated system steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area and Ambient Temperature — High signals are initiated from temperature elements that are located in two areas for HPCI and in two areas for RCIC to protect each system. Two instruments monitor each area. Two channels for each HPCI and RCIC Area, and Suppression Pool Area Ambient Temperature — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Eight temperature elements provide input to the HPCI and Suppression Pool Area Ventilation Differential Temperature - High Functions and eight temperature elements provide input to the RCIC and Suppression Pool Area Ventilation Differential Temperature - High Functions. The output of these temperature elements is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from two temperature elements for a total of four available channels (two for RCIC and two for HPCI). The HPCI Room Differential Temperature Channel temperature elements are located in the inlet and outlet of the area ventilation system. The RCIC Room Differential Temperature Channel inlet

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e., 3.g., 3.h., 3.i., 4.e., 4.g., 4.h., 4.i. Area and Differential Temperature — High (continued)

temperature elements are located in the HPCI/RCIC room hallway. The RCIC exhaust temperature elements are located in the outlet of the area ventilation system.

The Allowable Values are set low enough to detect a leak equivalent to 5 gpm. These Functions isolate the Group 6A and 6B valves, as appropriate.

3.f., and 4.f. HPCI and RCIC Leak Detection Time Delay

The HPCI Leak Detection and RCIC Leak Detection Time Delay Functions are provided to allow all the other systems that may be leaking into the pool area (as indicated by the high temperature) to be isolated before HPCI and/or RCIC are automatically isolated. This ensures maximum HPCI and RCIC System availability by preventing isolations due to leaks in other systems. These Functions are not assumed in any UFSAR transient or accident analysis.

There are four time delay relays (two for HPCI and two for RCIC). Two channels each for both HPCI and RCIC Leakage Detection Time Delay Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

No Allowable Values are specified in Table 3.3.6.1-1 for these Functions, as Analytical Limits are not established for this variable, only Nominal Trip Setpoints (NTSPs), which are controlled by plant procedures. The NTSPs are based on ensuring that the HPCI and RCIC systems are isolated in a sufficiently short time after a steam leak is detected so as to ensure that any potential release from such a leak remains bounded by the larger releases of the Design Basis Accidents (DBAs). In addition, the HPCI and RCIC time delays are staggered to allow the operator to determine which of these two systems is the source of leakage, allowing it to isolate, while maintaining the other system for core cooling. The time delay for the HPCI isolation is set shorter than that for RCIC as it has the larger steam line and hence the larger reactor vessel inventory loss if broken. Margin has been added to the NTSPs to account for instrument drift to specify acceptable as-found tolerances. These Functions isolate the Group 6A and 6B valves, as appropriate.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Water Cleanup System Isolation

5.a Differential Flow-High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area or differential temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow is sensed to prevent exceeding offsite doses. A time delay is provided to prevent spurious trips during most RWCU operational transients. This Function is not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from flow transmitters that are connected to the inlet (from the reactor vessel) and outlets (to the condenser (or radwaste) and to feedwater) of the RWCU System. The outputs of the transmitters are compared (in a common summer) and the resulting output is sent to two flow switches that trip when the sensed differential flow exceeds a predetermined value. If the difference between the inlet and outlets flow is too large, each flow switch generates an isolation signal. Two channels of Differential Flow — High Function are available and are required to be OPERABLE to ensure that no single instrument failure downstream of the common summer can preclude the isolation function.

The Differential Flow — High Allowable Value ensures that a "critical crack" in the RWCU piping is detected.

This Function isolates the Group 5 valves.

5.b., 5.c., and 5.f Area, Area Near Tip Room Ambient, and Area Ventilation Differential Temperature — High

RWCU area, area near TIP Room ambient, and area ventilation differential temperatures are provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred and is diverse to the high differential flow instrumentation for the hot portions of the RWCU System. If the small leak continues without isolation, offsite dose limits may be reached. In addition, the Area Near TIP Room Ambient

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.b., 5.c., and 5.f Area, Area Near Tip Room Ambient, and Area Ventilation Differential Temperature — High (continued)

Temperature - High Function isolates the RWCU System to ensure that the assumed environmental conditions are maintained in the first floor of the Reactor Building for equipment qualification purposes. Credit for these instruments is not taken in any transient or accident analysis in the UFSAR, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area, area near TIP Room ambient, and area ventilation differential temperature signals are initiated from temperature elements that are located in the area that is being monitored. Six temperature elements provide input to the Area Temperature □ High Function (four in the RWCU heat exchanger area and two in the RWCU pump area). However, only two channels are required to be OPERABLE (one in each trip system) to ensure that no single instrument failure can preclude the isolation function since the Area Differential Temperature High Function is able to detect breaks in the same areas as the Area Temperature - High Functions. As noted in footnote (d) to Table 3.3.6.1-1, in order to maintain coverage in both areas, each area (i.e., the heat exchanger area and the pump area) must have either an OPERABLE Area Temperature - High channel or an OPERABLE Area Ventilation Differential Temperature - High channel in each trip system.

Twelve temperature elements provide input to the Area Ventilation Differential Temperature - High Function. The output of these temperature elements is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from temperature elements that are located in the inlet and outlet of the area cooling system and for a total of six available channels (three in the RWCU heat exchanger area and three in the RWCU pump area). However, only two channels are required to be OPERABLE (one in each trip system) to ensure that no single instrument failure can preclude the isolation function since the Area Temperature - High Function is able to detect breaks in the same area as the Area Ventilation Differential Temperature - High Function. As noted in footnote (d) to Table 3.3.6.1-1, in order to maintain coverage in both areas, each area (i.e., the heat exchanger area and the pump area) must have either an OPERABLE Area Temperature – High channel or an OPERABLE Area Ventilation Differential Temperature - High channel in each trip system.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.b., 5.c., and 5.f Area, Area Near Tip Room Ambient, and Area Ventilation Differential Temperature — High (continued)

Four temperature elements provide input to the Area Near TIP Room Ambient Temperature - High Function. However, only two channels are required to be OPERABLE (one in each trip system) to ensure that no single instrument failure can preclude the isolation function.

The Area, Area Near TIP Room Ambient, and Area Ventilation Differential Temperature — High Allowable Values are set low enough to detect a leak equivalent to 5 gpm.

These Functions isolate the Group 5 valves.

5.d. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 4). The SLC System initiation signal is initiated from the SLC System initiation switch. There is no Allowable Value associated with this Function since the channels are mechanically actuated based solely on the position of the SLC System initiation switch. One channel of the SLC System Initiation Function is available and is required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7). As noted (footnote (e) to Table 3.3.6.1-1), this Function is only required to close the valves associated with one trip system, since the signal only provides input into one of the two trip systems. This results in isolating two of the three RWCU PCIVs.

5.e. Reactor Vessel Water Level — Low Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on Reactor Vessel Water Level-Low Low supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level — Low Low Function associated with RWCU isolation is not directly assumed

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.e. Reactor Vessel Water Level — Low Low (continued)

in the UFSAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

Reactor Vessel Water Level — Low Low signals are initiated from four level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level — Low Low Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 5 valves.

Shutdown Cooling System Isolation

6.a. Reactor Steam Dome Pressure - High

The Reactor Steam Dome Pressure — High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System (i.e., the shutdown cooling suction valves). This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario (i.e., a break of the low pressure RHR suction piping caused by exposure to relatively high pressure RPV fluid), and credit for the interlock is not assumed in the accident or transient analysis in the UFSAR.

The Reactor Steam Dome Pressure — High signals are initiated from two pressure switches that are connected to different taps on the suction piping of the "B" Recirculation System. Two channels of Reactor Steam Dome Pressure — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized; thus, over pressure protection is needed. The Allowable Value was chosen to be low enough to protect the RHR System piping from overpressurization (even with a time delay

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.a. Reactor Steam Dome Pressure – High (continued)

present), yet high enough to preclude spurious isolations of shutdown cooling during system startup and operation and to provide sufficient overlap with the low pressure isolations of the HPCI and RCIC turbines to allow the transition to shutdown cooling during plant shutdowns.

This Function isolates the Group 4 valves.

6.b. Reactor Vessel Water Level — Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level — Low Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the Recirculation Suction and MSL. The RHR Shutdown Cooling System isolation on Reactor Vessel Water Level-Low supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System when the system is in operation (i.e., the shutdown cooling suction valves are automatically isolated, and if both of the RHR shutdown cooling suction valves are not fully closed and reactor steam dome pressure is less than 135 psig (nominal), then the two inboard LPCI injection valves are also automatically isolated if a low reactor vessel water level signal is received).

Reactor Vessel Water Level — Low signals are initiated from four level indicating switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.b. Reactor Vessel Water Level — Low (continued)

The Reactor Vessel Water Level — Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level — Low Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level — Low Function is only required to be OPERABLE in MODE 3, to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel. In MODES 1 and 2, another isolation (i.e., Reactor Steam Dome Pressure — High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates the Group 4 valves.

6.c, Drywell Pressure - High

High drywell pressure indicates that the RHR Shutdown Cooling System piping downstream of the inboard isolation valve located in the drywell may have experienced a break. In order to prevent the level in the RPV from dropping below the top of active fuel if this were to occur, this Function will cause the RHR Shutdown Cooling System to isolate if the system is in use (i.e., the shutdown cooling suction valves are automatically isolated, and if both of the RHR shutdown cooling suction valves are not fully closed and reactor steam dome pressure is less than 135 psig (nominal), then the two inboard LPCI injection valves are also automatically isolated if a high drywell pressure signal is received). The Drywell Pressure - High Function associated with the RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling system is bounded by breaks of the Recirculation System and MSL.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.c, Drywell Pressure – High (continued)

Drywell Pressure - High signals are initiated from four pressure switches that are connected to the primary containment via four different penetrations. Four channels (two channels per trip system) of the Drywell Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Drywell Pressure - High Function is only required to be OPERABLE in Modes 1, 2, and 3 since these are the only MODES in which a LOCA could occur to cause the drywell to pressurize.

The Allowable Value was selected to be approximately the same as the ECCS Drywell Pressure-High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 4 valves.

Containment Cooling System Isolation

7.a Containment Pressure - High

High containment pressure indicates that a primary system break inside the containment has occurred. In order to maintain long term primary containment integrity under these conditions, the primary containment must be cooled. However, before Residual Heat Removal (RHR) System flow can be diverted from the LPCI flow path to the containment cooling flow path (e.g., suppression pool cooling), adequate core cooling must be assured. This assurance is provided by the Containment Cooling System Permissive Function, which receives inputs from LPCI initiation signals, reactor vessel shroud level signals and primary containment pressure signals. The LPCI initiation inputs and reactor vessel shroud level inputs to the Containment Cooling System Permissive logic can be overridden, if desired. Therefore, suppression pool cooling is still capable of performing the post accident containment cooling function if either of these two functions are inoperable. However, in order to prevent challenging the containment negative design pressure limit when spraying the containment, the Containment Pressure – High Function cannot be overridden (suppression pool spray valves are located on the same primary containment penetrations as the suppression pool cooling valves). Therefore, if certain combinations of Function 7.a channels are inoperable and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a Containment Pressure – High (continued)

channels are inoperable and untripped (such that the one-out-of-two taken twice logic is inhibited), then the logic will not allow the suppression pool cooling valves to be opened under post accident conditions, and the Suppression Pool Cooling System would be unavailable to perform the post accident containment cooling function. Consequently, this Function must be OPERABLE to support long term primary containment integrity by allowing containment cooling under post-LOCA conditions.

Additionally, if certain combinations of Function 7.a channels are in the tripped condition (such that the one-out-of-two taken twice logic is fulfilled), then the logic is not capable of automatically isolating the containment sprays to prevent containment pressure from dropping below the negative design pressure limit when the containment is being sprayed. Therefore, in order to protect primary containment integrity if the correct combination of Function 7.a channels are in the tripped condition such that automatic isolation capability is lost, the containment sprays should be inhibited.

Containment Pressure - High signals are initiated from four pressure switches that are connected to the primary containment via four different penetrations. Four channels of the Containment Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the containment cooling function under post accident conditions.

The Containment Pressure - High Function is only required to be OPERABLE in MODES 1, 2 and 3, since these are the only MODES in which a LOCA could cause pressurization of the primary containment. In MODES 4 and 5, the probability and consequences of such events are reduced due to the pressure and temperature limitations in these MODES.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a Containment Pressure – High (continued)

The Allowable Value was selected to be high enough to prevent the primary containment from exceeding the negative design pressure limit when spraying the containment.

This Function contributes to maintaining primary containment integrity under post accident conditions by: 1) allowing the use of the Suppression Pool Cooling System to fulfill the containment cooling function, and 2) preventing the containment negative design pressure limit from being exceeded by automatically isolating the sprays as pressure drops to the Allowable Value when spraying the containment.

ACTIONS

A Note has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, the Note has been provided to allow separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1, and A.2

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.b, 6.b, and 6.c and 24 hours for Functions other than Functions 2.a, 2.b, 6.b, and 6.c has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status.

(continued)

BASES

ACTIONS

A.1, and A.2 (continued)

This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

An additional Required Action is provided for Function 7.a. Required Action A.2 requires that within 24 hours the containment sprays be inhibited. If a Function 7.a channel is placed in trip per Required Action A.1, containment integrity could be threatened due to exceeding the containment negative design pressure limit. Inhibiting the containment sprays from spraying both the drywell and the suppression chamber removes this threat. One acceptable method of inhibiting containment spray operation is to verify that either the inboard or outboard containment spray Motor Operated Valve (MOV) on each applicable penetration is closed, and then to open the circuit breakers that supply electrical power to those MOVs (Note: if the inboard suppression chamber MOVs are closed, suppression pool cooling is not affected). Refer to LCO 3.6.2.4 for the Required Actions and associated Completion Times for inoperable RHR Suppression Pool Spray Subsystem(s). The 24 hour completion time is consistent with the time allowed to place the channel in trip.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal.

(continued)

BASES

ACTIONS

B.1 (continued)

This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. Note that Condition B can not exist for penetrations that are isolated by a single automatic isolation valve in series with a check valve (e.g., recirculation pump mini-purge penetrations and drywell pneumatics nitrogen supply penetration) since isolation capability is considered to be maintained by the check valve regardless of the ability of the automatic isolation functions to affect isolation of the penetration. For one-out-of-two taken twice logics, this would require both trip systems to have one channel OPERABLE or in trip. For the MSL High Flow Function, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For Functions that consist of channels that monitor several locations within a given area (e.g., different locations for monitoring MSL temperatures in the turbine building), this would require both trip systems to have one channel per location OPERABLE or in trip. For the Main Steam Line Tunnel Temperature - High Function, two channels per steam line, either OPERABLE or in trip, are required in either trip system. With this degree of coverage available in the steam tunnel, the logic is adequate to detect and isolate the MSIVs for a break of the size for which protection is necessary. For two-out-of-two once logics, this would require the trip system logic associated with either the inboard components or the outboard components to have two channels, each OPERABLE or in trip. For one-out-of-one once logics this would require the trip system logic associated with either the inboard components or the outboard components to have one channel OPERABLE or in trip. For the RWCU Area High Temperature and Area Ventilation High Differential Temperature Functions, each Function consists of channels that monitor several different locations. Therefore, this would require one channel per location (i.e., either one OPERABLE RWCU Area High Temperature channel or one OPERABLE Area Ventilation High Differential Temperature channel per location) to be OPERABLE or in trip (the channels are not required to be in the same trip system). Specific guidance for when Condition B exists is contained in plant procedures.

(continued)

BASES

ACTIONS

B.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

D.1, D.2.1, and D.2.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). Alternately, the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with an MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 8 hours.

(continued)

BASES

ACTIONS

E.1 (continued)

The allowed Completion Time of 8 hours is reasonable, based on operating experience to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels.

For the RWCU Differential Flow — High Function, if the flow element/transmitter monitoring RWCU flow to radwaste and condensate is the only portion of the channel inoperable, then the affected penetration flow path(s) may be considered isolated by isolating the RWCU return to radwaste and condensate.

Alternately, if it is not desired to isolate the affected penetration flow path(s), Condition H must be entered and its Required Actions taken.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1

[Deleted]

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, or any Required Action of Condition F is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

I.1 and I.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the SLC System is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the SLC System inoperable or isolating the RWCU System.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated). Actions must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

K.1 and K.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the containment cooling system permissive logic may not allow the Suppression Pool Cooling System to be placed in service under post accident conditions (i.e., with containment pressure greater than 2 psig). Therefore, the affected Suppression Pool Cooling subsystem(s) must be declared inoperable immediately per Required Action K.1. Refer to LCO 3.6.2.3 for the Required Actions and associated Completion Times for inoperable RHR Suppression Pool Cooling subsystem(s). As noted earlier, due to the common values between the two functions, this Action also makes the associated loop of Suppression Pool Spray inoperable and LCO 3.6.2.4 must also be entered. Alternatively, if the channel is

(continued)

BASES

ACTIONS

K.1 and K.2 (continued)

placed in trip but the containment sprays are not inhibited, containment integrity could be threatened due to exceeding the negative design pressure limit. Therefore, the primary containment must be declared inoperable immediately per Required Action K.2.

L.1 and L.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, either the primary containment vent and purge penetration flow paths must be isolated or administrative control of the primary containment vent and purge valves using continuous monitoring of alternate instrumentation must be established. These actions are required because the ability of the Function 2.c isolation signals to limit releases to less than 10 CFR 20 limits (if a LOCA were to occur during primary containment venting operations) is threatened. When Function 2.c is inoperable, the activity for which the isolation was intended must be terminated or administrative controls must be implemented. Acceptable administrative controls are implemented and venting or purging of primary containment may proceed, provided the following conditions are met: 1) an operator is stationed at the valve controls, and 2) that operator is instructed to terminate venting or purging when procedures direct valve closure.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions for Functions other than 5.a may be delayed for up to 6 hours provided the associated Function maintains isolation capability and for up to 6 hours for Function 5.a. For Functions 1.c, 1.e, and 1.f, the Allowed Outage Time (AOT) is applied at the instrument channel level, since the associated trip function and isolation capability are maintained via the companion logic channel. This is consistent with the "normal" trip arrangements with one instrument channel feeding each trip logic. Thus, a six hour AOT is applied to each instrument channel undergoing required testing. Upon completion of the Surveillance, or expiration of the applicable 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

This Note is based on the reliability analysis (Refs. 5 and 6) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary. Because the Ref. 5 and 6 analyses made no assumptions regarding the elapsed time between testing of consecutive channels in the same logic, it is not necessary to remove jumpers/relay blocks or reconnect lifted leads used to prevent actuation of the trip logic during testing of logic channels with instruments in series solely for the purpose of administering the AOT clocks, provided that the AOT allowance is not exceeded on a per instrument channel basis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.1 and SR 3.3.6.1.2

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.6.1.3, and SR 3.3.6.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.3, and SR 3.3.6.1.4 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency of SR 3.3.6.1.4 is based on the reliability analyses described in References 5 and 6. The Surveillance Frequency of SR 3.3.6.1.3 is based on engineering judgment and the reliability of the components.

SR 3.3.6.1.5, SR 3.3.6.1.6, SR 3.3.6.1.7 and SR 3.3.6.1.8

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.9

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 6.2.
2. UFSAR, Chapter 15.
3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.
4. UFSAR, Section 9.3.4.2.
5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
7. UFSAR, Section 7.3.
8. UFSAR, Section 15.2.1.5.

(continued)

BASES

REFERENCES (continued)

9. Revision 182 to Facility Operating License No. DPR-49 and NEDO-31400A, "Safety Evaluation for Eliminating the Boiling Water Reactor Main Steam Line Isolation Valve Closure Function and Scram Function of the Main Steam Line Radiation Monitor," October 1992.

10. NUREG 0737, Section II.E.4.2.(7).

B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND

The secondary containment isolation instrumentation automatically initiates closure of appropriate Secondary Containment Isolation Valves and/or Dampers (SCIV/Ds) and starts the Standby Gas Treatment (SBGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation and establishment of vacuum with the SBGT System ensures that fission products that leak from primary containment following a DBA, or are released outside primary containment, or are released during certain operations when primary containment is not required to be OPERABLE are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most channels include equipment (e.g., on-off sensors or bi-stable trip circuits) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (1) reactor vessel water level, (2) drywell pressure, (3) reactor building exhaust shaft high radiation, and (4) refueling floor exhaust duct high radiation. In addition, an offgas ventilation stack high radiation signal will cause the secondary containment to isolate and the SBGT System to start. However, this signal is not relied upon to isolate secondary containment or start SBGT for the mitigation of any transients or accidents. Therefore, this Function is not included in this LCO. Redundant sensor input signals from each parameter are provided for initiation of isolation.

(continued)

BASES

BACKGROUND (continued)

The outputs of the logic channels are arranged into two two-out-of-two trip system logics (for the reactor vessel water level and drywell pressure functions) or into two one-out-of-one trip system logics (for the reactor building exhaust shaft and refueling floor exhaust duct functions). One trip system logic initiates isolation of one automatic isolation valve (damper) and starts one SBGT subsystem while the other trip system logic initiates isolation of the other automatic isolation valve in the penetration and starts the other SBGT subsystem. Each trip system logic closes one of the two valves/dampers on each penetration and starts one SBGT subsystem, so that operation of either logic isolates the secondary containment and provides for the necessary filtration of fission products.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves/dampers and start the SBGT System to limit offsite doses.

Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves/Dampers (SCIV/Ds)," and LCO 3.6.4.3, "Standby Gas Treatment (SBGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses.

The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the secondary containment isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.6.2-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor or bi-stable trip circuit) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions when SCIV/Ds and the SBGT System are required.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Vessel Water Level — Low

Low Reactor Pressure Vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the SBGT System are initiated in order to minimize the potential of an offsite dose

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level — Low (continued)

release. The Reactor Vessel Water Level — Low Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation systems on and Reactor Vessel Water Level — Low support actions to ensure that any offsite releases are within the limits calculated in the safety analysis.

Reactor Vessel Water Level — Low signals are initiated from level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level-Low Allowable Value was chosen to be the same as the Reactor Protection System Reactor Vessel Level-Low Allowable Value (LCO 3.3.1.1), since this provides an early indication that the capability to cool the fuel is being threatened.

The Reactor Vessel Water Level — Low Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required.

2. Drywell Pressure — High

High drywell pressure can indicate a break in the Reactor Coolant Pressure Boundary (RCPB). An isolation of the secondary containment and actuation of the SBGT System are initiated in order to minimize the potential of an offsite dose release.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure — High (continued)

The isolation on high drywell pressure supports actions to ensure that any offsite releases are within the limits calculated in the safety analysis. However, the Drywell Pressure — High Function associated with the isolation is not assumed in any UFSAR accident or transient analyses. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation.

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell Pressure — High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude performance of the isolation function.

The Allowable Value was chosen to be the same as the ECCS drywell Pressure — High Function Allowable Value (LCO 3.3.5.1) since this is indicative of a Loss of Coolant Accident (LOCA).

The Drywell Pressure — High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

3, 4. Reactor Building Exhaust Shaft and Refueling Floor Exhaust Duct - High Radiation

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Exhaust - High Radiation is detected, secondary containment isolation and actuation of the SBGT System are initiated to limit the release of fission products as assumed in the UFSAR safety analyses (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3, 4. Reactor Building Exhaust Shaft and Refueling Floor Exhaust Duct - High Radiation (continued)

The Exhaust - High Radiation signals are initiated from radiation detectors that are located either in the reactor building exhaust shaft or in the exhaust duct coming from the refueling floor, respectively. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Exhaust Shaft - High Radiation Function and two channels of Refueling Floor Exhaust Duct - High Radiation Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

The Reactor Building Exhaust Shaft and Refueling Floor Exhaust Duct - High Radiation Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of a pipe break is low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are also required to be OPERABLE during OPDRVs because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery) must be provided to ensure that offsite dose limits are not exceeded.

ACTIONS

A Note has been provided to modify the ACTIONS related to secondary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the

(continued)

BASES

ACTIONS (continued)

Condition. However, the Required Actions for inoperable secondary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, the Note has been provided to allow separate Condition entry for each inoperable secondary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 1 and 2, and 24 hours for Functions 3 and 4 has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic isolation capability for the associated penetration flow path(s) or a complete loss of automatic initiation capability for the SBGT System. A Function is considered to be maintaining secondary containment isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIV/Ds in the associated penetration flow path and one SBGT subsystem can be initiated on an isolation signal from the given Function.

(continued)

BASES

ACTIONS

B.1 (continued)

For the Functions with two two-out-of-two logic trip systems (Functions 1 and 2), this would require one trip system to have two channels either OPERABLE or in trip. For the Functions with two one-out-of-one logic trip systems (Functions 3 and 4), this would require one trip system to have one channel either OPERABLE or in trip.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SBGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the secondary containment (closing the ventilation supply and exhaust automatic isolation dampers) and starting the associated SBGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operation to continue.

Alternately, declaring the associated SCIV/Ds or SBGT subsystem(s) inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components. One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without unnecessarily challenging plant systems.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains secondary containment isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 4 and 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated the 6 hour testing allowance does not significantly reduce the probability that the SCIV/Ds will isolate the associated penetration flow paths and that the SBGT System will initiate when necessary.

SR 3.3.6.2.1 and SR 3.3.6.2.2

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the reliability analysis of References 4 and 5.

SR 3.3.6.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIV/Ds and the SBGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.5 (continued)

Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 6.2.3.

2. UFSAR, Chapter 15.

3. UFSAR, Section 15.2.1.

4. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

B 3.3 INSTRUMENTATION

B 3.3.6.3 Low-Low Set (LLS) Instrumentation

BASES

BACKGROUND

The LLS logic and instrumentation is designed to mitigate the effects of postulated thrust loads on the Safety Relief Valve (SRV) discharge lines by preventing subsequent actuations with an elevated water leg in the SRV discharge line. It also mitigates the effects of postulated pressure loads on the torus shell or suppression pool by preventing multiple actuations in rapid succession of the SRVs subsequent to their initial actuation.

Upon initiation, the LLS logic will electrically control the opening and closing of the two LLS SRVs. The LLS setpoints are selected such that the LLS SRVs will stay open longer; thus, releasing more steam (energy) to the suppression pool, and hence more energy (and time) will be required for repressurization and subsequent SRV openings. The LLS logic increases the time between (or prevents) subsequent actuations to allow the vacuum breakers on the SRV discharge line to open and allow the high water leg created from the initial SRV opening to return to (or fall below) its normal water level; thus, reducing thrust loads from subsequent actuations to within their design limits. In addition, the LLS is designed to limit SRV subsequent actuations to one valve, so torus loads will also be reduced. However, this design feature is not critical since simultaneous valve opening is not a concern for the Mark I containment, and since simultaneous opening will not cause water swell problems for a BWR (Ref. 2).

The LLS instrumentation logic is arranged in two divisions with Logic channel A in one division and Logic channel B in the other division (Ref. 1). Each LLS logic channel (e.g., Logic A channel) controls one LLS valve. The LLS logic channels will not actuate their associated LLS valves at their LLS setpoints until the arming portion of the associated LLS logic is satisfied. Arming occurs when any one of the six SRVs opens as indicated by a signal from two of the three pressure switches located on its tailpipe coincident with a high reactor pressure scram signal. Each logic receives tailpipe arming signals from dedicated tailpipe pressure switches on each of the six SRVs, three in Logic A and three in Logic B. Each LLS logic (e.g., Logic A) receives its reactor

(continued)

BASES

BACKGROUND (continued)

pressure arming signal from the corresponding Reactor Protection System (RPS) trip system (e.g., LLS Logic A receives its reactor pressure arming signal from either RPS channel A_1 or A_2). Either of the two RPS reactor pressure inputs is capable of arming the associated LLS logic. The arming signal seals in until reset. The arming signal from one logic is sent to the other logic and performs the same function as the tailpipe arming signal (i.e., Logic A will arm if it has received a high reactor pressure signal and Logic B has armed).

After arming, opening and closing of each LLS valve is controlled by two reactor pressure switches, one of which causes the LLS SRV to open when its setpoint is exceeded, while the other causes the LLS SRV to reclose when reactor pressure has decreased to the reclose setpoint.

This logic arrangement prevents single instrument failures from precluding the LLS SRV function, since each logic controls one LLS SRV and one LLS SRV is sufficient to perform the LLS SRV function.

APPLICABLE SAFETY ANALYSES

The LLS instrumentation and logic function ensures that the containment loads remain within the primary containment design basis (Ref. 2).

The LLS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires OPERABILITY of sufficient LLS instrumentation channels to ensure successfully accomplishing the LLS function assuming any single instrumentation channel failure within the LLS logic. Therefore, the OPERABILITY of the LLS instrumentation is dependent on the OPERABILITY of the instrumentation channel Function specified in Table 3.3.6.3-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Value. A channel is inoperable if any of the trip setpoints of the instruments providing input to the channel are not within the respective required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

(continued)

BASES

LCO
(continued)

Allowable Values are specified for each LLS actuation Function in Table 3.3.6.3-1. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor steam dome pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., on-off sensor or bi-stable trip circuit) changes state. Analytical Limits, where established, are the limiting values of the process parameters used in safety analysis to define the margin to unacceptable consequences. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The Tailpipe High Pressure Allowable Value is based on ensuring that a proper arming signal is sent to the LLS logic. That is, the pressure switch is at a pressure that is sufficiently low so that an open SRV is detectable.

The Reactor Steam Dome Pressure — High signal is provided from RPS, and the same Reactor Steam Dome Pressure Allowable Value (LCO 3.3.1.1) is specified because it would be expected that LLS would be needed for pressurization events that result in a high pressure scram. Providing LLS after a scram has been initiated would prevent false initiations of LLS at 100% power. The LLS valve open and close Allowable Values are based on the safety analysis performed in Reference 4.

(continued)

BASES (continued)

APPLICABILITY

The LLS instrumentation is required to be OPERABLE in MODES 1, 2, and 3 since considerable energy is in the nuclear system and the SRVs may be needed to provide pressure relief. If the SRVs are needed, then the LLS function is required to ensure that the primary containment design basis is maintained. In MODES 4 and 5, the reactor pressure is low enough that the overpressure limit cannot be approached by assumed operational transients or accidents. Thus, LLS instrumentation and associated pressure relief is not required.

ACTIONS

A.1

The failure of any reactor steam dome pressure instrument channel to provide the arming, SRV opening or closing pressure setpoints for an individual LLS valve does not affect the ability of the other LLS SRV to perform its LLS function. A LLS valve is OPERABLE if the associated logic, (e.g., Logic A), has one Function 1 channel, two Function 2 channels, and two-out-of-three Function 3 channels associated with one of the three SRVs in the same division OPERABLE. Therefore, 24 hours is provided to restore the inoperable channel(s) to OPERABLE status (Required Action A.1). If the inoperable channel(s) cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action could result in an instrumented LLS valve actuation. The 24 hour Completion Time is considered appropriate because of the redundancy in the design (two LLS valves are provided and either LLS valve alone can perform the LLS function) and the very low probability of multiple LLS instrumentation channel failures, which render the remaining LLS SRVs inoperable, occurring together with an event requiring the LLS function during the 24 hour Completion Time. The 24 hour Completion Time is also based on the reliability analysis of Reference 3.

(continued)

BASES

ACTIONS (continued)

B.1

Since each LLS logic normally receives inputs from three SRV pressure switch channels per SRV (and also receives inputs from the other SRV pressure switch channels from the other logic by an arming signal), the LLS logic and instrumentation remains capable of performing its safety function if any SRV tailpipe pressure switch becomes inoperable since each SRV LLS arming logic can be actuated by any two out of the three pressure switches installed on the associated SRV tailpipe. Therefore, it is acceptable for plant operation to continue with only two tailpipe pressure switches OPERABLE on each SRV.

Required Action B.1 requires restoration of the tailpipe pressure switches to OPERABLE status prior to entering MODE 2 or 3 from MODE 4 to ensure that all switches are OPERABLE at the beginning of a reactor startup (this is because the switches are not accessible during plant operation). The Required Actions do not allow placing the channel in trip since this action could result in a LLS valve actuation.

C.1

A failure of two or more pressure switches associated with one SRV tailpipe could result in the loss of the LLS function (i.e., actuation of the SRV would go undetected by the LLS logic). However, both the limiting transient (MSIV closure event) and the limiting accident (small break LOCA with early isolation due to loss of offsite power) that the LLS System is designed to mitigate would result in all six SRVs lifting (Ref. 2). Therefore, it would be very unlikely that a single SRV would be required to arm both LLS logics. Therefore, it is acceptable to allow 14 days to restore two pressure switches to each of the associated SRVs to OPERABLE status (Required Action C.1). If at least two tailpipe pressure switches to each associated SRV cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required Action taken. The Required Actions do not allow placing the channels in trip since this action could result in a LLS valve actuation.

(continued)

BASES

ACTIONS

C.1 (continued)

A Note has been provided in the Condition to modify the Required Actions and Completion Times conventions related to LLS Function 3 channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LLS Function 3 channels provide appropriate compensatory measures for separate inoperable Condition entry for each SRV with inoperable tailpipe pressure switches.

D.1

If any Required Action and associated Completion Time of Conditions A, B, or C are not met, or if both LLS valves are inoperable due to inoperable channels, the LLS valves may be incapable of performing their intended function. Therefore, the associated LLS valve(s) must be declared inoperable immediately. A LLS valve is OPERABLE if the associated logic (e.g., Logic A) has one Function 1 channel, two Function 2 channels, and two out of three Function 3 channels associated with one of the three SRVs in the same division OPERABLE.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LLS instrumentation Function are located in the SRs column of Table 3.3.6.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

does not significantly reduce the probability that the LLS valves will initiate when necessary.

SR 3.3.6.3.1, and SR 3.3.6.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the reliability analysis of Reference 3.

A portion of the SRV tailpipe pressure switch channels is located inside the primary containment and is not available for testing during reactor operation. Therefore, SR 3.3.6.3.1 is only required on that portion of the channel that is outside primary containment.

SR 3.3.6.3.3, SR 3.3.6.3.4, and SR 3.3.6.3.5

CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specified channel. The system functional testing performed in LCO 3.4.3, "Safety Relief Valves (SRVs)" and LCO 3.6.1.5, "Low-Low Set (LLS) Safety Relief Valves (SRVs)," for SRVs overlaps this test to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency for SR 3.3.6.3.6 is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Figure 7.6-31.

2. NEDE-30021-P, Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for the DAEC, January 1983.

3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

4 UFSAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Standby Filter Unit (SFU) System Instrumentation

BASES

BACKGROUND

The SFU System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. Two independent SFU subsystems are each capable of fulfilling the stated safety function. The instrumentation and controls for the SFU System automatically initiate action to pressurize the control building envelope to minimize the consequences of radioactive material in the control building envelope.

In the event of a Control Building Intake Area Radiation - High signal, the SFU System is automatically started. The outside air is then passed through the charcoal filter and mixed with recirculated air to maintain the control building envelope slightly pressurized with respect to the atmosphere.

The SFU System instrumentation has two trip systems, with each trip system dedicated to its corresponding SFU. Each trip system receives input from the Control Building Intake Area Radiation - High Function, and is arranged in a one-out-of-one logic. The channels include electronic equipment (e.g., radiation monitors) that compare measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a SFU System initiation signal and a Control Building Ventilation System isolation signal to the initiation logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the SFU System to maintain the habitability of the control building envelope is explicitly assumed for certain accidents as discussed in the UFSAR safety analyses (Refs. 1 and 2). SFU System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents, does not exceed the limits of 10 CFR 50.67.

SFU System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of the SFU System instrumentation is dependent upon the OPERABILITY of the Control Building Intake Area Radiation - High channel Function. Each SFU must have one OPERABLE channel, with the radiation monitor setpoint within the specified Allowable Value. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

This Allowable Value (AV) is derived from the Analytical Limit (AL) used in the radiological dose analyses of the design basis LOCA (Ref. 1) and ensures that doses to control room personnel remain within the limits of 10 CFR 50.67. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., control building intake area radiation level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., radiation monitor output) changes state.

The Applicable Safety Analyses, LCO, and Applicability discussion for the Control Building Intake Area Radiation - High Function follows.

Control Building Intake Area Radiation — High

The control building intake area radiation monitors measure radiation levels exterior to the intake ducting of the control Building. A high radiation level may pose a threat to control room personnel; thus, this function automatically initiates the SFU System and places the Control Building Ventilation System in the isolation mode.

The Control Building Intake Area Radiation — High Function consists of two independent monitors. Two channels of Control Building Intake Area Radiation — High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude SFU System initiation. The Allowable Value was selected to ensure protection of the control room personnel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Control Building Intake Area Radiation — High (continued)

The Control Building Intake Area Radiation — High Function is required to be OPERABLE in MODES 1, 2, and 3 and during CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment, to ensure that control room personnel are protected during a LOCA, fuel handling event, or vessel draindown event. During MODES 4 and 5, when these specified conditions are not in progress (e.g., CORE ALTERATIONS), the probability of a LOCA or fuel damage is low; thus, the Function is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to SFU System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable SFU System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable SFU System instrumentation channel.

A.1, and A.2

With a Control Building Intake Area Radiation-High Channel inoperable, the initiation capability of the associated SFU subsystem is lost. Therefore, the associated SFU subsystem(s) must be declared inoperable within 1 hour per Required Action A.1, or must be placed in the isolation mode of operation, (i.e., the SFU in operation and the Control Building Ventilation System isolated, within 1 hour per Required Action A.2. Placing the subsystem in the isolation mode ensures that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the SFU subsystem(s) in operation must provide for automatically re-initiating the subsystem(s) upon restoration of power following a loss of power to the SFU subsystem(s).

(continued)

BASES

ACTIONS

A.1, and A.2 (continued)

The 1 hour Completion Time is intended to allow the operator time to place the SFU subsystem(s) in the isolation mode of operation, and is acceptable because it minimizes risk while allowing time for restoration of channels, or for placing the associated SFU in its safety mode, or for entering the applicable Conditions and Required Actions for the inoperable SFU subsystem(s).

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other channel is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 4 and 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the SFU System will initiate when necessary.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (continued)

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the reliability analyses of References 4 and 5.

SR 3.3.7.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.4, "Standby Filter Unit (SFU) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience that has shown these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 15.2.

2. UFSAR, Section 6.4.4.

3. [Deleted]

4. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kv emergency bus voltages and the Startup and Standby Transformer secondary winding voltages. Offsite power is the preferred source of power for the 4.16 Kv emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite Diesel Generator (DG) power sources. The monitors also provide start permissive signals for the low pressure ECCS pumps and inputs to various load shedding circuits.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. Each bus is monitored at two different voltage levels, which can be considered as two different undervoltage Functions: 4.16 kV Emergency Bus Loss of Voltage and 4.16 kV Emergency Bus Degraded Voltage. A third LOP Function monitors the voltages of the secondary windings of both the Startup and Standby Transformers (4.16 kV Emergency Transformer Supply Undervoltage). Each of these Functions provide inputs to various required actions such as: bus transfers, load sheds, or DG starts. Each emergency bus is monitored for the Loss of Voltage Function by a single undervoltage relay. Each bus is monitored for the Degraded Voltage Function by four relays whose contacts form a coincidence logic matrix such that either of the A1 or A2 contacts and either of the B1 or B2 contacts must close to initiate the required actions in the associated division (i.e., one-out-of-two taken twice). For the Emergency Transformer Supply Undervoltage Function, the secondary winding of the Standby Transformer is monitored by two channels. One channel provides an input to initiate the required actions in one division, while the other channel provides input to initiate the required actions in the other division. Each channel of the Emergency Transformer Supply Undervoltage Function includes two relays. Both of the secondary windings of the Startup Transformer (i.e., a separate secondary winding is associated with each division) are

(continued)

BASES

BACKGROUND (continued)

monitored by a single relay for this Function; the relay that monitors the winding associated with each division provides an input to initiate the required actions in that division. The initiation logic for each division receives inputs from both the Startup and Standby Transformers secondary windings (i.e., two-out-of two relay logic). The various channels include monitoring equipment (i.e., current transformers or voltage transformers) and relays that compare measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP signal to its associated trip logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features (ESF) to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 1, 2, and 3 analyzed accidents in which a loss of offsite power is assumed. The LOP instrumentation also serves to provide protection for the ESF from damage that could occur due to prolonged degraded voltage conditions on the grid. The initiation of the DGs on a LOP or LOCA signal, and concurrent initiation of the ECCS on a LOCA signal ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Disconnecting the emergency buses from the offsite sources and starting the DGs when a prolonged degraded voltage condition exists ensures that the ESF (e.g., large pump motors) are not damaged due to starting with insufficient voltage present.

Accident analyses credit the loading of the DG based on the loss of offsite power during a LOCA. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. Analytical Limits are the limiting values of the process parameters for use in safety analysis. Margin is provided between the Allowable Value and the Analytical Limits to allow for process, calibration (i.e., M&TE) and some instrument uncertainties. Additional margin is provided between the Allowable Value and the trip setpoint to allow for the remaining instrument uncertainties (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power has been completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power and the various loads connected to the emergency bus are load shed when the voltage on the bus drops below the Loss of Voltage Function Allowable Values. This ensures that adequate power will be available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) (continued)

The Bus Undervoltage Allowable Values are low enough to prevent power supply transfer and load shedding unless offsite power has truly been lost, but high enough to ensure that power is available to the required equipment.

One channel of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus is only required to be OPERABLE in MODES 1, 2, 3, and when the associated DG is required to be OPERABLE by LCO 3.8.2, to ensure that no single instrument failure can preclude the DG function. (One channel provides input to the initiation logic for its respective division.) Refer to LCO 3.8.1, "AC Sources-Operating," and 3.8.2, "AC Sources-Shutdown," for Applicability Bases for the DGs.

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

Four channels of 4.16 kv Emergency Bus Undervoltage (Degraded Voltage) Function per associated bus are only required to be OPERABLE in MODES 1, 2, and 3, and when the associated DG is required to be OPERABLE by LCO 3.8.2, to ensure that no single instrument failure can preclude the DG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

3. 4.16 kV Emergency Transformer Supply Undervoltage

An undervoltage condition on either the Startup Transformer secondary winding or the Standby Transformer secondary winding indicates that offsite power may be lost and is unable to supply sufficient power for proper operation of the applicable equipment. This Function is similar to Function 1, except whereas Function 1 monitors each emergency bus voltage, Function 3 monitors the voltage of the offsite sources directly via the secondary windings of the two transformers associated with the two offsite sources. Therefore, when an undervoltage condition exists on an individual transformer, the supply breakers from that transformer to the emergency buses are tripped open. If an undervoltage condition exists on both transformers, then the supply breakers from both transformers to the emergency buses are tripped open and a start signal is sent to the associated DG. This ensures that adequate power will be available to the required equipment.

The Emergency Transformer Supply Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. 4.16 kV Emergency Transformer Supply Undervoltage (continued)

Two channels of 4.16 kv Emergency Transformer Supply Undervoltage Function (one channel from the secondary winding of the Startup Transformer and one channel from the secondary winding of the Standby Transformer) per associated emergency bus are only required to be OPERABLE in MODES 1, 2, and 3, and when the associated DG is required to be OPERABLE by LCO 3.8.2, to ensure that no single failure can preclude the DG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more channels of Function 1 or 3 inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure (within the LOP instrumentation), and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG

(continued)

BASES

ACTIONS

A.1 (continued)

initiation), Condition C must be entered and its Required Action taken. The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1 and B.2

With certain combinations of multiple Function 2 channels inoperable, the ability of the 4.16 kv Emergency Bus Undervoltage (Degraded Voltage) Function to separate the emergency buses from the offsite sources and to start the DG(s) may be lost. Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels of Function 2 result in automatic initiation capability being lost in one or both divisions. If initiation capability is lost, the associated DG(s) must be declared inoperable within 1 hour from discovery of loss of initiation capability for feature(s) in one or both divisions. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 or LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

With one Function 2 channel inoperable, or with certain combinations of multiple Function 2 channels inoperable, the ability of the 4.16 kv Emergency Bus Undervoltage (Degraded Voltage) Function to initiate the required actions in either or both divisions is maintained by the remaining OPERABLE channels. In this situation, the requirement to place a channel in trip within 1 hour as in Required Action A.1, or to immediately declare the associated DG inoperable, is overly conservative. The 24 hour Completion Time of Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 24 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS (continued)

C.1

If the Required Action and associated Completion Time is not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1 and SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequencies is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in this interval is a rare event.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.3 and SR 3.3.8.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequencies is based upon the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 6.2.

2. UFSAR, Section 6.3.

3. UFSAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the Motor Generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and Groups 1 through 5 isolation logic.

Each RPS Electrical Protection Assembly (EPA) will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both in-series EPAs), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram solenoids may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between the RPS buses and the alternate power supply. Each of these circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic.

(continued)

BASES

BACKGROUND (continued)

Together, a circuit breaker and its sensing logic constitute an EPA. If the output of the MG set or the alternate power supply exceeds predetermined limits of overvoltage, undervoltage, or underfrequency, after a short time delay, (if applicable), a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE SAFETY ANALYSES

The RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of each RPS EPA is dependent on the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two EPAs are required to be OPERABLE for each inservice power supply. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS EPA failure can preclude the function of RPS bus powered components. Each inservice EPA's trip logic setpoints are required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS EPA trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

(continued)

BASES

LCO (continued)

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip coil) changes state. The Allowable Values (AV) are based on the nominal power supply voltage and frequency requirements for RPS components because there are no Analytic Limits in the safety analysis from which to derive the AVs. The nominal trip setpoints are determined from the AVs, accounting for instrument errors and provide adequate protection. The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The Allowable Values for the instrument settings are based on the RPS providing $\geq$ 57 Hz, 120 V ± 10%, to the RPS bus. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS EPAs is essential to disconnect the RPS bus powered components from the MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS EPAs is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODES 3, 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If one RPS EPA for an inservice power supply (MG set or alternate) is inoperable, or one RPS EPA on each inservice power supply is inoperable, the OPERABLE EPA will still provide protection to the RPS bus powered components under degraded voltage or frequency conditions. However, the reliability and

(continued)

BASES

ACTIONS (continued)

A.1 (continued)

redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable EPA to OPERABLE status. If the inoperable EPA cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE EPAs may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE EPA and the low probability of an event requiring RPS electric power monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternately, if it is not desired to remove the power supply from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both EPAs for an inservice power supply (MG set or alternate) are inoperable or both EPAs in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable EPA for each inservice power supply cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE EPAs may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration of the EPA or removal of the associated power supply from service.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1 or 2, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS EPA(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODES 3, 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action D.1 results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the system will automatically trip open the associated EPA. Only one signal per EPA is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated EPA would be inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.3 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. UFSAR, Section 7.2.1.1.2.

2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Coolant Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes more heat from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The Reactor Coolant Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable speed motor driven recirculation pump, a Motor Generator (MG) set to control pump speed and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core. The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat

(continued)

BASES

BACKGROUND (continued)

is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 55 to 100% of RTP) without having to move control rods and disturb desirable flux patterns.

In addition, the combination of core flow and THERMAL POWER is normally maintained such that core thermal-hydraulic oscillations do not occur. These oscillations can occur during two-loop operation, as well as single-loop and no-loop operation. Plant procedures include requirements of this LCO as well as other vendor and NRC recommended requirements and actions to minimize the potential of core thermal-hydraulic oscillations.

Each recirculation loop is manually started from the control room. The MG set provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled by varying the speed of the corresponding recirculation pump.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Coolant Recirculation System is an initial condition assumed in the design basis Loss of Coolant Accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement. Since recirculation loop flow is controlled by varying recirculation pump speed, a limit on the speed mismatch between operating recirculation pumps has been imposed. For some limited low probability accidents (e.g., intermediate break size LOCAs) with the recirculation loop operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions the Core Spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, operating procedures have been put into place limiting the allowable mismatch in speed between the recirculation pumps.

Analyses indicate that above 69.4% RTP the Loop Select Logic could be expected to function at a speed differential up to 14% of their average speed. Below 69.4% RTP the Loop Select Logic would be expected to function at a speed differential up to 20% of their average speed. The recirculation loop speed mismatch limits imposed to prevent the LPCI Loop Select Logic from selecting the wrong loop for injection bound the recirculation flow mismatch limits for LOCA analyses. If the reactor is operating on one recirculation pump, the Loop Select Logic trips that pump before making the loop selection.

The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the UFSAR.

A plant specific LOCA analysis has been performed assuming only Single Loop Operation (SLO). This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The transient analyses of Chapter 15 of the UFSAR have also been performed for SLO (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During SLO, modification to the Reactor Protection System (RPS) Average Power Range Monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR limits adjusted for SLO are specified in the COLR. The APRM Flow Biased High Scram allowable value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Two recirculation loops are normally required to be in operation with the recirculation pump speeds matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternately, with only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and APRM Flow Biased High Scram allowable value (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of Reference 3. The idle loop is isolated electrically by disconnecting the breaker to the recirculation pump motor generator (M/G) set drive motor prior to reactor startup or, if disabled during reactor operation, within 24 hours of entering SLO. With either one or two recirculation pumps in operation, core flow as a function of THERMAL POWER must be outside the Exclusion Region specified in the COLR to avoid the potential for thermal hydraulic instability.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

With no recirculation loops in operation, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor mode switch must be placed in the Shutdown position Immediately. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown position is permitted by the definition of an Immediate Completion Time. Operation in natural circulation could place the plant in or near the Exclusion Region for thermal hydraulic instability. Manually scramming the reactor is the recommended method of exiting the Exclusion Region when the plant is operating in natural circulation, since restarting a recirculation pump in this condition could result in the initiation of thermal hydraulic instability.

B.1

With one or two recirculation loops in operation in the Exclusion Region of the power/flow map, immediate action must be initiated to exit the Exclusion Region. This action can be to insert control rods or to increase core flow. Entries into the Exclusion Region are not part of normal operation. An entry may occur as a result of an abnormal event, such as a single recirculation pump trip. In these events, operation in the Exclusion Region may be needed to prevent equipment damage, but actual time spent inside the Exclusion Region is minimized.

(continued)

BASES

ACTIONS

B.1 (continued)

Though each operator action can prevent the occurrence and protect the reactor from an instability, the APRM flow-biased scram function is designed to suppress global oscillations, the most likely mode of oscillation, prior to exceeding the fuel safety limit (Ref. 4). While global oscillations are the most likely mode, protection from out-of-phase oscillations are provided through avoidance of the Exclusion Region and administrative controls on reactor conditions which are primary factors affecting reactor stability.

C.1

If recirculation pump speed mismatch is not within limits, the pump speed mismatch must be restored or one recirculation pump must be tripped within two hours. For some limited low probability accidents with the recirculation loops operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions, Core Spray itself is adequate to prevent fuel temperature from exceeding allowable limits. However, to limit the probability even further, a two hour Completion Time has been established. The two hour Completion Time provides a reasonable time for the operator to restore the pump speed mismatch to within limits.

D.1

With the requirements of the LCO not met for reasons other than Conditions A, B, or C, the Single Loop Operation (SLO) limits must be applied for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR), "LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." Should a LOCA occur with one recirculation loop not in operation when the limits specified for SLO have not been applied, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to apply the limits specified for SLO or restore the inoperable loop to operating status.

(continued)

BASES

ACTIONS

D.1 (continued)

Alternatively, if the limits specified for SLO are applied, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence and transient analysis.

The 24 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the necessary SRs to meet the requirements of the LCO and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

E.1

With the Required Action and associated Completion Time of Condition C, or D not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for speed mismatch. For some limited low probability accidents with the recirculation loop operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions, Core Spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, a limitation has been placed on the allowable variation in speed between the recirculation pumps.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

Analyses indicate that above 69.4% RTP the LPCI Loop Select Logic could be expected to function at a speed differential up to 14% of average recirculation pump speed with the specification limit set at approximately ± 10% of average recirculation pump speed to provide margin. Below 69.4% RTP the Loop Select Logic would be expected to function at a speed differential up to 20% of average recirculation pump speed with the specification limit set at approximately ± 15% of average recirculation pump speed to provide margin. If the reactor is operating on one recirculation pump, the Loop Select Logic trips the pump before making the loop selection. The mismatch is measured in terms of percent of the speed of one recirculation pump compared to the speed of the other recirculation pump. If the speed mismatch exceeds the specified limits and cannot be restored within two hours, one recirculation pump shall be tripped. The SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop operation. The Surveillance must be performed within 24 hours after both loops are in operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is consistent with the Surveillance Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

SR 3.4.1.2

This SR ensures the reactor THERMAL POWER and core flow are within appropriate parameter limits to prevent uncontrolled power oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal hydraulic instability if operation is permitted in the Exclusion Region shown in the Core Operating Limits Report. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience and the operators' inherent knowledge of reactor status, including significant changes in THERMAL POWER and core flow.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.4.3.3.

2. UFSAR, Section 15.1.3.

3. NEDC-32980P, “Safety Analysis Report for Extended Power Uprate,” Revision 1, April 2001.

4. UFSAR Section 15.3.4.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Coolant Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the Reactor Coolant Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two-thirds core height, the vessel can be reflooded and coolant level maintained at two-thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains eight jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis Loss of Coolant Accident (LOCA) analysis evaluated in Reference 1.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet Pumps satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two-thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Coolant Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Coolant Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Coolant Recirculation System is not required to be in operation, and when not in operation, sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided; i.e., meeting criterion a means that data collection required for evaluation against criterion b is unnecessary. In addition, when recirculation pump speeds are less than 60% of rated, criterion c allows an engineering evaluation to be performed to determine that the criteria a and b data are acceptable. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns", engineering judgement of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by three Notes. Notes 1 and 2 affect the entire SR. The third Note only affects criterion c. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed when THERMAL POWER is $\leq$ 21.7% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

Note 3 allows criterion c to be applied when recirculation pump speed is ≤ 60% of rated speed. Criterion c allows engineering judgment to be applied to an evaluation of the data collected for criteria a and b, to determine if the data is acceptable. This evaluation can take into account factors such as the influence of instrument accuracy and natural circulation at core flows less than 50% of rated. This data should be collected and evaluated every 24 hours when recirculation pump speeds are ≤ 60% of rated. If multiple data points are collected at pump speeds ≤ 60%, the trend of such data should be evaluated for acceptability. When this data is collected with recirculation pump speeds > 60% of rated, criteria a or b limits must always be met.

REFERENCES

1. UFSAR, Section 15.2.1.

2. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.

3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety Relief Valves (SRVs) and Safety Valves (SVs)

BASES

BACKGROUND

The ASME Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of SRVs and SVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the Reactor Coolant Pressure Boundary (RCPB).

The SRVs and SVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The SRVs can actuate by either of two modes: the safety mode or the relief mode. However, for the purpose of this LCO, only the safety mode is required. The SVs actuate only in the safety mode. In the safety mode (or spring mode of operation), the spring loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. The safety mode function of both SRVs and SVs satisfies the Code requirement. A power generation design basis function of the SRVs is also to prevent opening of the SVs during normal plant isolations and load rejections.

Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool while the SVs discharge directly to the drywell airspace. The SRVs that provide the relief mode are the Low-Low Set (LLS) valves and the Automatic Depressurization System (ADS) valves. The LLS requirements are specified in LCO 3.6.1.5, "Low-Low Set (LLS) Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS — Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all Main Steam Isolation Valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, 6 valves (any combination of SRVs and SVs) are assumed to operate in the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

safety mode. The analysis results demonstrate that the design SRV and SV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the SRVs.

SRVs and SVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The safety function of 8 valves; (SRVs and SVs) is available; however, to satisfy the assumptions of the safety analysis, only 6 valves (any combination of SRVs and SVs) are required to be OPERABLE (Refs. 1 and 2). All eight valves are specified to be OPERABLE so that the reactor will not be operated for an unlimited period of time with any one valve inoperable. The requirements of this LCO are applicable only to the capability of the SRVs and SVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

The SRV and SV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the UFSAR are based on these setpoints, but also include the additional uncertainties of a 3% (high) error in the nominal setpoint to provide an added degree of conservatism.

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, all SRVs and SVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The SRVs and SVs may be required to provide pressure relief to discharge energy from the core so that the Residual Heat Removal (RHR) System is capable of dissipating the core heat via either the Suppression Pool Cooling mode or the Shutdown Cooling mode.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The SRV and SV function is not needed during these conditions.

ACTIONS

A.1

With the safety function of one SRV or SV inoperable, the remaining OPERABLE SRVs or SVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with any combination of two SRVs or SVs inoperable. However, the overall reliability of pressure relief system is reduced because additional failures in the remaining OPERABLE SRVs or SVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

The 30 day Completion Time to restore the inoperable SRVs or SVs to OPERABLE status is based on the relief capability of the remaining SRVs and SVs, the low probability of an event requiring SRV and SV actuation, and that single failure criterion is retained.

(continued)

BASES

ACTIONS (continued)

B.1

With the safety function of any combination of two SRVs or SVs inoperable, the remaining OPERABLE SRVs and SVs are capable of providing the necessary overpressure protection; however, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE SRVs or SVs could result in failure to adequately relieve pressure during a limiting event. Therefore, a more restrictive Completion Time is specified.

The 7 day Completion Time to restore at least one inoperable valve to OPERABLE status takes into account the low probability of an event requiring SRV and SV actuation, coupled with an additional single failure of an SRV or SV where the relief capability would be inadequate. The 7 Day Completion Time is consistent with other requirements where a loss of redundancy has occurred.

C.1 and C.2

With less than the minimum number of required SRVs and SVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of the inoperable SRVs or SVs cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1 or B.1 or if the safety function of any combination of three or more SRVs or SVs is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the SRVs and SVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the SRV and SV lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the INSERVICE TESTING PROGRAM. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The SRV and SV setpoints are $\pm$ 3% for OPERABILITY; however the valves are reset to ± 1% during the Surveillance to allow for drift.

The Surveillance Frequency is in accordance with the INSERVICE TESTING PROGRAM requirements contained in the ASME Code. This Surveillance must be performed during shutdown conditions.

SR 3.4.3.2

The actuator of each dual function safety/relief valves (S/RVs) is stroked to verify that the pilot valve strokes when manually actuated. The actuator test is performed by energizing a solenoid that pneumatically actuates a plunger. The plunger is connected to the second stage disc located within the main valve body. When steam pressure actuates the plunger during plant operation, this allows pressure to be vented from the top of the main valve piston, allowing reactor pressure to lift the main valve piston, which opens the main valve disc. The test will verify movement of the plunger in accordance with vendor recommendations. However, since this test is performed prior to establishing the reactor pressure needed to overcome main valve closure forces, the main valve disc will not stroke during the test.

This SR, together with the valve testing performed as required by the ASME Code for pressure relieving devices (ASME OM Code - 2001 through 2003 Addenda), verify the capability of each relief valve to perform its function.

Valve testing will be performed at a steam test facility, where the valve (i.e., main valve and pilot valve) and an actuator representative of the actuator used at the plant will be installed on a steam header in the same orientation as the plant installation. The test conditions in the test facility will be similar to those in the plant installation, including ambient temperature, valve insulation, and steam conditions. The valve will then be leak tested, functionally tested to ensure the valve is capable of opening and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.2 (continued)

closing (including stroke time), and leak tested a final time. Valve seat tightness will be verified by a cold bar test, and if not free of fog, leakage will be measured and verified to be below design limits. In addition, for the safety mode of S/RVs, an as-found setpoint verification and as-found leak check are performed, followed by verification of set pressure, and delay time. The valve will then be shipped to the plant without any disassembly or alteration of the main valve or pilot valve components.

The combination of the valve testing and the valve actuator testing provide a complete check of the capability of the valves to open and close, such that full functionality is demonstrated through overlapping tests, without cycling the valves.

If a valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the SRV is not considered inoperable.

This SR is not applicable to the SVs, due to their design which does not include the manual relief capability, nor do they have a discharge line that can become blocked.

The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

REFERENCES

1. UFSAR, Section 5.2.2.2.1.

2. UFSAR, Section 15.1.2.

3. ASME Code for Operation and Maintenance of Nuclear Power Plants.

4. NUREG 1482, Guidelines for Inservice Testing at Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the Reactor Coolant Pressure Boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and UFSAR Section 3.1.2.4.1 (Ref. 1).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment atmosphere, if possible, so as not to mask RCS Operational LEAKAGE detection. Note that RCS LEAKAGE does not include weepage through SRVs into the Suppression Pool, since the weepage is not into the primary containment atmosphere and is not quantifiable.

This LCO deals with protection of both the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a Loss of Coolant Accident.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests that, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 2 and 3) shows that leakage rates significantly higher than the allowed LEAKAGE will precede crack instability (Ref. 4).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of Intergranular Stress Corrosion Cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell sump capacity.

RCS Operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS Operational LEAKAGE shall be limited to:

a. <u>Unidentified LEAKAGE</u>

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the Primary Containment Air Sampling System and Drywell Sump System can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

(continued)

BASES

LCO (continued)

b. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

c. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY In MODES 1, 2, and 3, the RCS Operational LEAKAGE LCO applies, because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS Operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

BASES (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. The increase does not necessarily violate the absolute unidentified LEAKAGE limit, therefore, an option exists to allow continued reactor operation if certain susceptible components are determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type piping is very susceptible to IGSCC. Note also that once LEAKAGE is attributed to a specific source, that LEAKAGE can be considered to be identified and can be applied against the identified limit, rather than the unidentified limit.

The 4 hour Completion Time is reasonable to properly reduce the unidentified LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, other methods may be used to quantify LEAKAGE within the guidelines of References 4 and 5. It is permissible to use pre-existing information, in conjunction with secondary measurements (e.g., Drywell pressure and temperature), to verify that LEAKAGE remains within limits by looking for step changes in conditions or to perform calculations to estimate LEAKAGE. The complete failure to demonstrate that RCS LEAKAGE is within limits, on the required Frequency, constitutes a failure to meet this SR, notwithstanding entrance into Conditions and Required Actions of LCO 3.4.5.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In conjunction with alarms and other administrative controls, the Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 5).

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 3.1.2.4.1.

2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.

3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.

4. UFSAR, Section 5.2.5.3.2.

5. Generic Letter 88-01, Supplement 1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR Section 3.1.2.4.1 (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

Limits on LEAKAGE from the Reactor Coolant Pressure Boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired. Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. The Bases for LCO 3.4.4, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by various independently monitored variables, such as sump level changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the Drywell Sump System.

The Drywell Sump System monitors the LEAKAGE collected in the floor drain sump and the equipment drain sump. The unidentified LEAKAGE is collected in the floor drain sump and consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The identified LEAKAGE is collected in the equipment drain sump and consists of LEAKAGE from various expected LEAKAGE sources. Both the drywell floor drain sump and the drywell equipment drain sump have transmitters that supply level indications in the reactor building.

Both the floor drain sump and equipment drain sump level indicators have switches that start and stop the sump pumps when required. A sump fill timer starts each time either sump is pumped down to the low level setpoint.

(continued)

BASES

BACKGROUND (continued)

If either sump fills to the high level setpoint before the sump fill timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit.

Both the floor drain sump and equipment drain sump also have a sump pump out timer which measures the time from automatic or manual initiation of the pump to the low level setpoint. The time of pump operation is converted to a leakage rate. An alarm annunciates in the control room if the leakage rate exceeds a preset limit.

The flow indicators in the discharge lines of the drywell floor drain sump pumps and drywell equipment drain sump pumps provide flow indications in the control room. The pumps can also be started from the control room.

The equipment drain sump subsystem instrumentation consists of one equipment drain sump flow integrator, the equipment drain sump fill timer and the equipment drain sump pump out timer. The floor drain sump subsystem instrumentation likewise consists of one floor drain sump flow integrator, the floor drain sump fill timer and the floor drain sump pump out timer. The Drywell Sump System is OPERABLE when any one of these six devices is OPERABLE.

The Primary Containment Air Sampling System continuously monitors the primary containment atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity may be attributed to RCPB steam or reactor water LEAKAGE. The Primary Containment Air Sampling System is not capable of quantifying LEAKAGE rates, but is sensitive enough to indicate increased LEAKAGE rates.

The Primary Containment Air Sampling System provides a backup system to the Drywell Sump System. The Primary Containment Air Sampling System consists of six channels (two gaseous, two Iodine, and two particulate). The Primary Containment Air Sampling System is OPERABLE when any one of the six available channels is OPERABLE.

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 2 and 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room.

A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 4).

Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

The Drywell Sump System is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE. Because the sump fill and pump out timers receive their input signals directly from the sump pump motor circuits, the inability to start the pump may cause the associated timers to be inoperable. Some common failures are direct pump failure, loss of power to the circuit, failure of the sump level switches or inability to open one of the sump isolation valves that is interlocked with the sump pump. Any failure associated with the pump subsystem should be evaluated for its impact on the ability of the associated timer(s) to measure LEAKAGE. For example, a loss of automatic pump start on high sump level with manual pump operation still available would not cause the sump pump out timer to be inoperable, but would impact the OPERABILITY of the sump fill timer.

Since the flow element for each sump is not directly tied to the sump pump for its input signals, they are not affected in the same way as the timers. However, the loss of flow through the flow element prevents the flow indicator from performing its intended function of measuring LEAKAGE, and even though all of its associated SRs continue to be met, it should be considered inoperable.

(continued)

BASES

LCO (continued)

It should be noted that system isolation in response to Required Actions of LCO 3.6.1.3, would not render these instruments inoperable under NOTE 3 of LCO 3.6.1.3, provided the system could be unisolated as allowed by the NOTE 1 of LCO 3.6.1.3, as manual pump operation is allowed.

The total loss of the Drywell Sump System results from the loss of all sump timers and flow indicators (either directly or indirectly). The Drywell Sump System remains OPERABLE when any one of the six devices is OPERABLE.

An alternate to the drywell floor drain sump subsystem is the drywell equipment drain sump subsystem. Because of the physical size of the sumps, it is possible to detect the required LEAKAGE limit (5 gpm) and rate limit (2 gpm/24 hrs) during the period of time it takes to actually overflow from one sump to the other. Once the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump subsystem can be used to quantify LEAKAGE. However, the alarm settings for the equipment drain sump instruments must be reset to detect the lower limit for unidentified LEAKAGE (Reference 5). In this condition, all LEAKAGE measured by the drywell equipment drain sump subsystem is assumed to be unidentified LEAKAGE. The opposite situation is also allowed, where the equipment drain sump is allowed to overflow into the floor drain sump. In this configuration, the alarm settings need not be reset, as they would conservatively quantify all LEAKAGE as unidentified and alarm at the appropriate limit. The other monitoring systems provide additional indication to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. The Primary Containment Air Sampling System provides a backup system to the Drywell Sump System. The Primary Containment Air Sampling System is OPERABLE when any one of the six available channels is OPERABLE. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

(continued)

BASES (continued)

ACTIONS

A.1

With the Drywell Sump System inoperable, no other form of sampling can provide the equivalent information to quantify LEAKAGE. However, the Primary Containment Air Sampling System will provide indication of changes in LEAKAGE.

With the Drywell Sump System inoperable, operation may continue for 24 hours. The 24 hour Completion Time is acceptable, based on operating experience, considering no other method to quantify LEAKAGE is available.

B.1

With all six gaseous and particulate Primary Containment Air Sampling System channels inoperable, action to restore the required Primary Containment Air Sampling System to OPERABLE status is required immediately. This is allowed because LEAKAGE can still be quantified by the Drywell Sump System.

C.1 and C.2

With all six gaseous and particulate Primary Containment Air Sampling System channels and the Drywell Sump System inoperable, no means of detecting LEAKAGE is available. This condition does not provide the required diverse means of LEAKAGE detection. The Required Action is to restore either of the inoperable monitoring systems to OPERABLE status within 4 hours to regain the intended LEAKAGE detection diversity. The 4 hour Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If any Required Action of Condition A or C cannot be met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 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 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required Primary Containment Air Sampling System. The check gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator and floor drain sump flow integrator. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. These tests ensure that the monitors can perform their function in the desired manner and also verifies the Primary Containment Air Sampling System alarm functions properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency considers instrument reliability, and operating experience has shown it proper for detecting degradation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.3

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of required equipment drain sump fill and sump pump out timers and floor drain sump fill and sump pump out timers. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency considers channel reliability. Operating experience has proven this Frequency is acceptable.

SR 3.4.5.4 and SR 3.4.5.5

These SRs are for the performance of a CHANNEL CALIBRATION of required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator, floor drain sump flow integrator, equipment drain sump fill and sump pump out timers and floor drain sump fill and sump pump out timers. The calibration verifies the accuracy of the instrument string, excluding the level elements located inside containment. The level elements have no adjustable parts and thus, do not require calibration. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency considers channel reliability. Operating experience has proven these Frequencies are acceptable.

REFERENCES

1. UFSAR Section 3.1.2.4.1.

2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.

3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.

4. UFSAR, Section 5.2.5.2.3.

5. DAEC Operating License Revision # 169, 9-19-90.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND

During circulation in normal operating conditions, the reactor coolant acquires radioactive materials due to release of fission products from "tramp" uranium on the outside of the fuel cladding and activation of corrosion products in the reactor coolant. There is the potential for fuel leaks into the reactor coolant that will contribute to the level of radioactive materials due to release of fission products. These radioactive materials in the reactor coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 50.67 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 50.67 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the UFSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a Main Steam Line Break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 3). The limits on the specific activity of the primary coolant

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

ensure that the 2 hour Total Effective Dose Equivalent (TEDE) doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 50.67.

The limit on specific activity is plant specific analysis of the radiological consequences of a Main Steam Line Break DBA.

RCS Specific Activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to $\leq$ 0.2 µCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 50.67 limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

ACTIONS

A.1 and A.2

When the reactor coolant Specific Activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is $\leq$ 2.0 µCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the Specific Activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient Specific Activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to $\leq$ 0.2 µCi/gm within 48 hours, or if at any time it is > 2.0 µCi/gm, it must be determined at least once every 4 hours and all the main steam lines, including the main steam line drains, must be isolated within 12 hours. Isolating the main steam lines including drains, precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 50.67 during a postulated MSLB accident.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance is performed to ensure iodine remains within limits during normal operation. The analysis is performed using filtrate from a 0.45µ filter. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 50.67

2. UFSAR, Sections 15.0.8 and 15.0.9.

3. UFSAR, Section 15.2.1.5

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System – Hot Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to $\leq$ 212°F. This decay heat is removed in preparation for performing Refueling or Cold Shutdown maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling loops of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both pumps and a heat exchanger in one loop or one pump and an

(continued)

BASES

LCO (continued)

associated heat exchanger in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Thus, two RHR pumps in a common RHR subsystem, together with the associated heat exchanger and flow path components, constitutes two OPERABLE RHR shutdown cooling subsystems. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation of one RHR shutdown cooling subsystem is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Note 1 permits both required RHR shutdown cooling subsystems to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one required RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RCIC Steam Supply Line Pressure - Low isolation pressure the RHR System must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RCIC Steam Supply Line Pressure - Low isolation pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above the RHR shutdown cooling isolation interlock pressure (which is slightly higher than the

(continued)

BASES

APPLICABILITY (continued)

RCIC Steam Supply Line Pressure - Low isolation pressure) because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RCIC Steam Supply Line Pressure - Low isolation pressure is typically accomplished by condensing the steam in the main condenser. Providing this operational overlap between the different pressures allows a smooth transition between these methods of decay heat removal. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS)(LCO 3.5.1, "ECCS — Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System — Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR) — High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR) — Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3

With one required RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore, an alternate method of decay heat removal must be provided.

With both required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

The required cooling capacity of the alternate method should be ensured by verifying (by administrative means) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Main Steam System, the Reactor Water Cleanup System and, feed and bleed to radwaste or condenser.

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or recirculation pump must be restored without delay. Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability. An alternate method of reactor coolant circulation that can be used includes (but is not limited to) Reactor Water Cleanup System.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This Surveillance verifies that one required RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The RHR shutdown cooling subsystem or recirculation pump flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the RCIC Steam Supply Line Pressure - Low isolation pressure, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

SR 3.4.7.2

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Shutdown Cooling System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Shutdown Cooling System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.2 (continued)

same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

This SR is modified by a Note that states the SR is not required to be performed until 12 hours after reactor steam dome pressure is less than RCIC Steam Supply Line Pressure - Low isolation pressure. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering the Applicability.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant $\leq$ 212°F. This decay heat is removed in preparation for performing Refueling maintenance operations or for keeping the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling loops of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water (RHRSW) System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, one RHRSW pump providing cooling to the heat exchanger, and the associated piping and valves. In addition, the necessary portions of the Emergency Service Water and River Water Supply Systems and the Ultimate Heat Sink are also required to provide appropriate cooling and a suction source to each required RHRSW pump. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping.

(continued)

BASES

LCO (continued)

Thus, to meet the LCO, both pumps and a heat exchanger in one loop or one pump and an associated heat exchanger in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Thus, two RHR pumps in a common RHR subsystem, together with the associated heat exchanger and flow path components, constitute two OPERABLE RHR shutdown cooling subsystems. In addition, the RHR cross tie valve (MO-2010) may be opened to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem. Additionally, each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring nearly continuous operation of a recirculation pump or one RHR shutdown cooling subsystem is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Note 1 permits both required RHR shutdown cooling subsystems to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one required RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

(continued)

BASES (continued)

APPLICABILITY

In MODE 4, the RHR Shutdown Cooling System must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 212°F. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3, with reactor steam dome pressure greater than or equal to the RCIC Steam Supply Line Pressure - Low isolation pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above the RHR shutdown cooling isolation interlock pressure (which is slightly higher than the RCIC Steam Supply Line Pressure - Low isolation pressure) because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RCIC Steam Supply Line Pressure - Low isolation pressure is typically accomplished by condensing the steam in the main condenser. Providing this additional overlap between the different pressures allows a smooth transition between these methods of decay heat removal. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS - Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the RCIC Steam Supply Line Pressure - Low isolation pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System — Hot Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR) — High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR) — Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial

(continued)

BASES

ACTIONS (continued)

entry into the Condition. However, the Required Actions for inoperable shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by administrative means) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. For example, if the length of time after shutdown is such that losses to ambient surroundings are sufficiently large so as to prevent RCS temperature from increasing, Required Action A.1 would be fulfilled for one inoperable subsystem. Other alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, feed and bleed to the torus via SRVs, Reactor Water Cleanup System, reactor cavity floodup and Fuel Pool Cleanup System return to the reactor cavity.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation except as permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This alternate method may consist of the losses to ambient surroundings if such losses are sufficiently large so as to prevent RCS temperature from increasing and if natural circulation has been established. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability. Alternate methods of reactor coolant circulation that can be used include (but are not limited to) raising reactor water level above the minimum natural circulation level (i.e., lowest turnaround point for water in the steam separator) and Reactor Water Cleanup System.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance verifies that one required RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The RHR shutdown cooling subsystem or recirculation pump flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

SR 3.4.8.2

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.2 (continued)

Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Shutdown Cooling System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Shutdown Cooling System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.2 (continued)

accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (Reference 7) contains P/T limit curves for heatup, cooldown, and inservice leakage and hydrostatic testing, and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides limits for both heatup and criticality.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the Reactor Coolant Pressure Boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

(continued)

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leakage and hydrostatic testing.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T Limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The elements of this LCO are:

a. RCS pressure, temperature and heatup or cooldown rates are within the limits specified in the PTLR;

b. The temperature difference between the reactor vessel bottom head coolant and the Reactor Pressure Vessel (RPV) coolant is within the limits specified in the PTLR during recirculation pump startup;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is within the limits specified in the PTLR during recirculation pump startup;

d. RCS pressure and temperature are within the criticality limits specified in the PTLR, prior to achieving criticality; and

e. The temperatures at the reactor vessel head flange and the shell adjacent to the head flange are within the limits specified in the PTLR when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leakage and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

(continued)

BASES

LCO (continued)

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits in the PTLR while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 212°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

Condition C is modified by a Note requiring Required Action C.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within limits is required periodically when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, this Frequency permits a reasonable time for assessment and correction of minor deviations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be initiated and discontinued when the criteria given in the relevant plant procedure for starting and ending the activity are satisfied. During heatups and cooldowns, the temperatures at the reactor vessel shell adjacent to the shell flange, the reactor vessel bottom drain, recirculation loops A and B, and the reactor vessel bottom head shall be monitored. During inservice hydrostatic or leak testing, the reactor vessel metal temperatures at the outside surface of the bottom head in the vicinity of the control rod drive housing and reactor vessel shell adjacent to the shell flange shall be monitored.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

SR 3.4.9.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.9.3 and SR 3.4.9.4

Differential temperatures within the applicable limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation pump (Ref. 8) are satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.3 and SR 3.4.9.4 (continued)

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

For SR 3.4.9.3, an acceptable means of measuring Reactor Pressure Vessel (RPV) coolant temperature is by using the saturation temperature corresponding to reactor steam dome pressure.

Acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 include but are not limited to comparing the temperatures of the operating recirculation loop and the idle loop. The idle loop and RPV coolant temperature using saturation temperature corresponding to reactor steam dome pressure, or the idle loop and the bottom head coolant temperature with flow through the bottom head drain are acceptable means.

SR 3.4.9.3 and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during a recirculation pump startup, since this is when the stresses occur. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required.

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

Limits on temperature at the reactor vessel head flange and the shell adjacent to the head flange are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

SR 3.4.9.5 requires that temperatures at the reactor vessel head flange and the shell adjacent to the head flange must be verified to be above the limits within the Surveillance Frequency before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 (continued)

RCS temperature ≤ 80°F, more frequent checks of the temperatures at the reactor vessel head flange and the shell adjacent to the head flange are required by SR 3.4.9.6 because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the temperatures at the reactor vessel head flange and the shell adjacent to the head flange are required periodically by SR 3.4.9.7 to ensure the temperatures are within the specified limits.

The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program. The Frequency for SR 3.4.9.5 and SR 3.4.9.6 reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The Frequency for SR 3.4.9.7 is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. However, per SR 3.0.4, the Surveillance needs to be met prior to tensioning, i.e., verified within the Surveillance Frequency prior to the start of tensioning. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperatures ≤ 80°F in Mode 4. SR 3.4.9.7 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature
≤ 100°F in Mode 4. The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the limits specified.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix G, December 1995
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR), see Appendix A of the Technical Requirements Manual.
8. UFSAR, Section 15.1.5.1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND

The reactor steam dome pressure is an assumed initial condition of design basis accidents and transients and is conservative to the value used in the determination of compliance with reactor pressure vessel overpressure protection criteria.

APPLICABLE SAFETY ANALYSES

The reactor steam dome pressure of $\leq$ 1025 psig is an initial condition for the analysis of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% fuel cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)") (Reference 1).

Reference 2 vessel overpressure protection analysis evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the LCO limit on dome pressure ensures that the assumptions of the overpressure protection analysis are conservative.

Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specified reactor steam dome pressure limit of $\leq$ 1025 psig ensures the plant is operated within the assumptions of the accident and transient analyses. Operation above the limit may result in a plant response more severe than analyzed.

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam and the events that may challenge the fuel thermal limits are possible.

In MODE 3, the limit is not applicable because the reactor is shut down and the stored energy in the primary system is less than that assumed in the accident analyses.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4, and 5, the reactor pressure is well below the required limit due to the pressure and temperature limits of these MODES, and no anticipated events will challenge either the fuel thermal limits or the vessel overpressure limit.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is $\leq$ 1025 psig ensures that the initial conditions of the accident and transient analyses are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown the Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 15.0.10.

2. UFSAR, Section 5.2.2.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.1 ECCS — Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a Loss of Coolant Accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) System, and the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the Condensate Storage Tank (CST), it is capable of providing a source of water for the HPCI and CS systems.

On receipt of an initiation signal, after the appropriate time delays for the Diesel Generators (DGs) to start and provide power to the 4160 VAC bus, assuming the concurrent Loss of Offsite Power (LOOP), ECCS pumps automatically start; the system aligns and the pumps inject water, taken either from the CST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, the ADS timed sequence would be allowed to time out and open the selected Safety Relief Valves (SRVs) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly precluding HPCI from injecting to the vessel, and the LPCI and CS subsystems cool the core.

(continued)

BASES

BACKGROUND (continued)

Water from the break returns to the suppression pool where it is used again. Water in the suppression pool may be circulated through a heat exchanger cooled by the RHR Service Water System to provide long term cooling, after adequate core cooling has been established and after the applicable timed interlocks have expired, approximately one minute following a LOCA. Depending on the location and size of the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break. The RCIC System performs a similar function as HPCI, but has reduced makeup capability. Nevertheless, it will help maintain inventory and cool the core while the RCS is still pressurized following a Reactor Pressure Vessel (RPV) isolation.

The combined operation of all ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started approximately 5 seconds after AC power is available. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow on-line testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There is one LPCI System (Ref. 2), consisting of four motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the "selected" recirculation loop. The LPCI System is equipped with a Loop Select Logic that determines which, if any, of the recirculation loops has been broken and "selects" the non-broken loop for injection. (Ref. 15).

(continued)

BASES

BACKGROUND (continued)

The LPCI System is designed to provide core cooling at low RPV pressure assuming operation of 3 out of 4 RHR pumps. Upon receipt of an initiation signal, all four LPCI pumps are automatically started (A and B pumps approximately 10 seconds after AC power is available, and C and D pumps approximately 15 seconds after AC power is available). RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the "selected" recirculation loop. The LPCI swing bus, a "power-seeking" logic, ensures that the AC distribution bus for the LPCI and Recirculation System valves that must re-align for injection into the RPV are connected to an OPERABLE DG, assuming LOOP (Ref. 15). When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the selected recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for the four LPCI pumps to route water from the suppression pool, to allow on-line testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the Feedwater System line, where the coolant is distributed within the RPV through the Feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard Main Steamline Isolation Valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psid to 1135 psid, vessel to pump suction). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed.

(continued)

BASES

BACKGROUND (continued)

As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Although the HPCI System is designed to achieve a design flow rate within 30 seconds from the receipt of an initiation signal (Ref. 3), the accident analysis shows acceptable results assuming HPCI start times (from initiation signal to full flow and injection valve full open) as long as 45 seconds (Ref. 9). Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS subsystem discharge lines are kept full of water using a "keep fill" system (jockey pump system). The HPCI system is normally aligned to the CST. The height of water in the CST maintains the piping full of water from the HPCI pump discharge to the HPCI pump discharge check valve.
The HPCI system discharge piping near the normally closed injection valve to the feedwater system absorbs heat from feedwater via conduction. This has the potential to form a localized steam bubble in the HPCI discharge piping and cause a water hammer upon HPCI initiation. Although the water hammer has been analyzed and shown not to adversely affect HPCI system operation, the Condensate Service Water System is utilized as a keep fill to maintain the HPCI discharge piping between the normally closed injection valve and pump discharge check valve charged with water to prevent possible bubble formation and minimize water hammer transient effects. When HPCI suction is aligned to the suppression pool and the HPCI system is not in operation, either the Condensate Service Water (high pressure) keep fill or the low pressure keep fill from the CST must be utilized in order to support system OPERABILITY. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water.

The ADS (Ref. 4) consists of 4 of the 6 SRVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the

(continued)

BASES

BACKGROUND (continued)

operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup. Each of the SRVs used for automatic depressurization is equipped with one nitrogen accumulator and associated inlet check valves. The accumulator provides the pneumatic power to actuate the valves.

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in Reference 5. The required analyses and assumptions are defined in Reference 8. The results of these analyses are also described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is $\leq$ 2200°F;

b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is $\leq$ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a LOCA, failure of Division II of 125 VDC power is considered the most severe failure. One ADS valve failure is analyzed as an equipment “out-of-service” condition. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Each ECCS injection/spray subsystem and four ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the LPCI System, and one HPCI System. The low pressure ECCS subsystems are defined as the two CS subsystems and the LPCI System. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

The LPCI System may be considered OPERABLE during alignment and operation for decay heat removal (i.e.- Shutdown Cooling) when below the actual RHR Shutdown Cooling interlock pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary. In addition, the risk of a LOCA during the transition from the RHR interlock pressure to cold shutdown is minimal.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is $\leq$ 150 psig, HPCI is not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. In MODES 2 and 3, when reactor steam dome pressure is $\leq$ 100 psig, ADS is not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "RPV Water Inventory Control."

(continued)

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI System. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI System and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If any one RHR pump is inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE pumps provide adequate core cooling during a LOCA. However, overall LPCI reliability is reduced, because a single failure in one of the remaining OPERABLE pumps, concurrent with a LOCA, may result in LPCI not being able to perform its intended safety function. The 30 day Completion Time is based on a reliability study cited in Reference 12 that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowable repair times (i.e., Completion Times).

B.1

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of out of service times (i.e., Completion Times).

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If any one low pressure Core Spray (CS) subsystem is inoperable in addition to one or two RHR pump(s), adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystems. This condition results in a compliment of remaining OPERABLE low pressure ECCS (i.e., one CS and either two or three LPCI pumps) whose makeup capacity is bounded by the minimum makeup capacity evaluated in the accident analysis, which assumes the limiting single component failure of Division II of 125 VDC (Reference 11). However, overall ECCS reliability is reduced because a single active component failure in the remaining low pressure ECCS, concurrent with a design basis LOCA, could result in the minimum required ECCS equipment not being available. Since both a CS subsystem is inoperable and a reduction in the makeup capability of the LPCI System has occurred, a more restrictive Completion Time of 72 hours is required to restore either the CS subsystem or the RHR pump(s) to OPERABLE status. The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

D.1

If both low pressure Core Spray (CS) subsystems are inoperable, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystem (LPCI). However, overall ECCS reliability is reduced because a single active component failure in the LPCI subsystem, concurrent with a design basis LOCA, could result in the minimum required ECCS equipment not being available. Since both CS subsystems are inoperable, a more restrictive Completion Time of 72 hours is required to restore one CS subsystem to OPERABLE status.

(continued)

BASES

ACTIONS

D.1 (continued)

The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

E.1 and E.2

If the inoperable low pressure ECCS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1 and F.2

If the HPCI System is inoperable and the RCIC System is immediately verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be immediately verified, however, Condition J must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available.

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

A 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

G.1 and G.2

If any one RHR pump is inoperable in addition to an inoperable HPCI System, the inoperable RHR pump or the HPCI System must be restored to OPERABLE status within 7 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a DBA-LOCA could result in the minimum complement of ECCS not being available to perform the intended safety function. Since a high pressure system (HPCI) is inoperable and a loss of redundancy in the LPCI System has occurred, a more restrictive Completion Time of 7 days is required to restore either the HPCI System or RHR pump to OPERABLE status. The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

H.1 and H.2

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, in addition to an inoperable HPCI System, the inoperable low pressure ECCS subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this Condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

or the low pressure ECCS subsystem to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. This Completion Time has been found to be acceptable through operating experience.

I.1 and I.2

If any one ADS valve is inoperable in addition to the HPCI System being inoperable, adequate core cooling (for small break LOCAs) is ensured by the remaining ADS valves in combination with either the CS or LPCI subsystems. However, overall ECCS reliability is significantly reduced because a single active component failure (i.e., failure of one of the three remaining OPERABLE ADS valves) concurrent with a small break LOCA could result in the minimum required ECCS equipment not being available. Since both an ADS valve and the HPCI System are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the ADS valve or the HPCI System to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

J.1 and J.2

If any Required Action and associated Completion Time of Condition F, G, H or I is not met, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to $\leq$ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

K.1

The LCO requires four ADS valves to be OPERABLE in order to provide the ADS function. Reference 9 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only three ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced, because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. This 30 day Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probalistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

L.1 and L.2

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystem. However, overall ECCS reliability is reduced because a single active component failure concurrent with a LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure system (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS subsystem or the ADS valve to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

M.1 and M.2

If any Required Action and associated Completion Time of Condition K or L is not met, or if two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to $\leq$ 100 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

N.1

When multiple ECCS subsystems are inoperable, as stated in Condition N, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1 (continued)

criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the ECCS injection/spray subsystem is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS injection/spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

SR 3.5.1.2

Verifying the correct alignment for power operated and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to manual valves unless the valves are being manipulated to serve as all or part of a system vent flow path opened under administrative control, as described in the SR Note (and Bases paragraph below). In this case, the SR Note allows the licensee to credit administratively controlled manual action to close the system vent flow path in order to maintain system Operability during system venting and performance of the gas accumulation SR. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of this SR was derived from the INSERVICE TESTING PROGRAM requirements for performing valve testing. The Frequency is further justified because the valves are operated under procedural control and because improper valve position would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include a stationing of a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

In Mode 3 with reactor steam dome pressure less than the actual RHR interlock pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by Note 1, which allows the LPCI System to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Manual alignment of the RHR cross tie valves (MO2010 and V-19-48) may only be credited when the valves are soft seated per normal operating procedure in order to prevent inoperability due to thermal binding. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. At the low

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

pressures and decay heat loads associated with operation in Mode 3 with reactor steam dome pressure less than the RHR interlock pressure, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

Verification that a 30 day supply of nitrogen exists for each ADS accumulator ensures adequate nitrogen 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, each ADS valve can be actuated at least 5 times up to 30 days following a LOCA (Reference 4). This SR can be met by either: 1) verifying that the drywell nitrogen header supply pressure is $\geq$ 90 psig, or 2) when drywell nitrogen header supply pressure is < 90 psig, using the actual accumulator check valve leakage rates obtained from the most-recent tests to determine, analytically, that a 30 day supply of nitrogen exists for each accumulator. The results of this analysis can also be used to determine when the 30 day supply of nitrogen will no longer exist for individual ADS accumulators, and when each ADS valve would subsequently be required to be declared inoperable, assuming the drywell nitrogen supply pressure is not restored to $\geq$ 90 psig. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into consideration administrative controls over operation of the nitrogen system and alarms for low nitrogen pressure.

SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.6

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME Code requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values may be established during preoperational testing or by analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.6 (continued)

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow is tested at both the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Reactor steam pressure must be $\geq$ 940 psig to perform SR 3.5.1.5, the high pressure test, and $\leq$ 160 psig to perform SR 3.5.1.6, the low pressure test. Adequate steam flow is represented by approximately 0.5 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.5 and SR 3.5.1.6 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hour allowance to reach the required pressure and flow is sufficient to achieve stable conditions for testing and provide a reasonable time to complete the SRs.

The Frequency for SR 3.5.1.4 and SR 3.5.1.5 is in accordance with the INSERVICE TESTING PROGRAM requirements. The Surveillance Frequency for SR 3.5.1.6 is controlled under the Surveillance Frequency Control Program. The Frequency for SR 3.5.1.6 is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at this Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.7

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. As part of this SR for the LPCI system, a verification of the "power-seeking" logic for the LPCI "Swing Bus" (1B34A and 1B44A), i.e., the ability to transfer power sources from either AC Essential Bus upon loss of power (either AC or 125 VDC), is included. This verification, when coupled with the verification of the "break-before-make" coordination of the breakers in SR 3.8.7.2, demonstrate the ability of the Swing Bus to perform its intended safety function in support of the Loop Select design of the LPCI system without compromising the independence of the AC Distribution System (Reference 16). This SR also ensures that the HPCI System will automatically restart on an RPV low water level signal received subsequent to an RPV high water level trip and that the suction is automatically transferred from the CST to the suppression pool on a CST Low Water Level Signal or Torus High Water Level Signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown that these components usually pass the SR when performed at this Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The first Note excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance. The second Note is added to SR 3.5.1.7 to allow the surveillance to be met by performing the test in any number of sequential and/or overlapping steps, rather than in a single, contiguous performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

This is necessary because testing the entire LPCI Loop Select Logic would interfere with forced reactor coolant circulation and/or decay heat removal functions and require multiple LPCI System starts to demonstrate all the Loop Select Logic features (e.g., injections paths, single loop operation and "swing" bus). Therefore, each of the required features can be tested either individually or in appropriate combinations (including overlap with other LCO 3.5.1 surveillances, the Instrumentation surveillances required by LCO 3.3.5.1 and the "swing" bus breaker coordination surveillance in LCO 3.8.7), such that the overall function is tested on the required Frequency.

SR 3.5.1.8

The ADS designated SRVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.9 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at this Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation, since the valves are individually tested in accordance with SR 3.5.1.9. This prevents an RPV pressure blowdown.

SR 3.5.1.9

The actuator of each ADS dual function safety/relief valves (S/RVs) is stroked to verify that the pilot valve strokes when manually actuated. For the S/RVs, the actuator test is performed by energizing a solenoid that pneumatically actuates a plunger.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.9 (continued)

The plunger is connected to the second stage disc located within the main valve body. When steam pressure actuates the plunger during plant operation, this allows pressure to be vented from the top of the main valve piston, allowing reactor pressure to lift the main valve piston, which opens the main valve disc. The test will verify movement of the plunger in accordance with vendor recommendations. However, since this test is performed prior to establishing the reactor pressure needed to overcome main valve closure forces, the main valve disc will not stroke during the test.

This SR, together with the valve testing performed as required by the ASME Code for pressure relieving devices (ASME OM Code - 2001 through 2003 Addenda), verify the capability of each relief valve to perform its function.

Valve testing will be performed at a steam test facility, where the valve (i.e., main valve and pilot valve) and an actuator representative of the actuator used at the plant will be installed on a steam header in the same orientation as the plant installation. The test conditions in the test facility will be similar to those in the plant installation, including ambient temperature, valve insulation, and steam conditions. The valve will then be leak tested, functionally tested to ensure the valve is capable of opening and closing (including stroke time), and leak tested a final time. Valve seat tightness will be verified by a cold bar test, and if not free of fog, leakage will be measured and verified to be below design limits. In addition, for the safety mode of S/RVs, an as-found setpoint verification and as-found leak check are performed, followed by verification of set pressure, and delay time. The valve will then be shipped to the plant without any disassembly or alteration of the main valve or pilot valve components.

The combination of the valve testing and the valve actuator testing provide a complete check of the capability of the valves to open and close, such that full functionality is demonstrated through overlapping tests, without cycling the valves.

SR 3.5.1.8 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.3.2.2.3.

2. UFSAR, Section 6.3.2.2.4.

3. UFSAR, Section 6.3.2.2.1.

4. UFSAR, Section 6.3.2.2.2.

5. UFSAR, Section 15.0.9.

6. [Deleted]

7. [Deleted]

8. 10 CFR 50, Appendix K.

9. UFSAR, Section 15.2.1.

10. 10 CFR 50.46.

11. UFSAR, Section 6.3.1.1.2.

12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

13. [Deleted]

14. NEDO-10739, Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, January 1973.

15. UFSAR, Section 7.3.1.1.2.4.

16. J. Hall (NRC) to L. Liu (IELP), "LPCI Swing Bus Design Modification (TAL No. 69556), "dated January 19, 1989.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control

BASES

BACKGROUND

The RPV contains penetrations below the TS 2.1.1.3 Safety Limit that have the potential to drain the reactor coolant inventory below the TS 2.1.1.3 Safety Limit. If the water level should drop below the TS 2.1.1.3 Safety Limit, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulation in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error). It is assumed, based on engineering judgement, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The RPV water level must be controlled in Modes 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by SAFETY Limit 2.1.1.3.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TS 2.1.1.3 Safety Limit to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TS 2.1.1.3 Safety Limit in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually started to provide defense-in-depth should an unexpected draining event occur. A low pressure ECCS injection/spray subsystem consists of either one Core Spray (CS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. In MODES 4 and 5, the RHR System cross tie valve is not required to be closed.

The LCO is modified by a Note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TS 2.1.1.3 Safety Limit.

(continued)

BASES (continued)

APPLICABILITY

RPV water inventory control is required in MODES 4 and 5. Requirements on water inventory control in other MODES are contained in LCOs in Section 3.3, Instrumentation, and other LCOs in Section 3.5, ECCS, RCIC, and RPV Water Inventory Control. RPV water inventory control is required to protect Safety Limit 2.1.1.3 which is applicable whenever irradiated fuel is in the reactor vessel.

ACTIONS

A.1 and B.1

If the required low pressure ECCS injection/spray subsystem is inoperable, it must be restored to OPERABLE status within 4 hours. In this Condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem, however the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4 hour Completion Time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgement that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TS 2.1.1.3 Safety Limit for ≥ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

C.1, C.2, and C.3

With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level below the TS 2.1.1.3 Safety Limit,

(continued)

BASES

ACTIONS C.1, C.2, and C.3 (continued)

there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action C.1 requires verification of the capability to establish the secondary containment boundary in less than the DRAIN TIME. The required verification confirms actions to establish the secondary containment boundary are preplanned and necessary materials are available. The secondary containment boundary is considered established when one Standby Gas Treatment (SBGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

Verification that the secondary containment boundary can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment. Secondary containment penetration flow paths form a part of the secondary containment boundary. Required Action C.2 requires verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME. The required verification confirms actions to isolate the secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that the secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SBGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Required Action C.3 requires verification of the capability to place one SBGT subsystem in operation in less that the DRAIN TIME. The required verification confirms actions to place SBGT subsystem in operation are preplanned and necessary materials are available. Verification that a SBGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, D.3, and D.4

With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, Required Action E.1 is also applicable.

Required Action D.1 requires immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The Note to Required Action D.1 states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TS 2.1.1.3 Safety Limit for ≥ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TS 2.1.1.3 Safety Limit, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

The secondary containment provides a control volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action D.2 requires that actions be immediately initiated to establish the secondary containment boundary. With the secondary containment boundary established, one SBGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of the

(continued)

BASES

ACTIONS

D.1, D.2, D.3, and D.4 (continued)

secondary containment boundary. Required Action D.3 requires that actions be immediately initiated to verify that each secondary containment penetration flow path is isolated or to verify that it can be manually isolated from the control room.

One SBGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Required Action D.4 requires that actions be immediately initiated to verify that at least on SBGT subsystem is capable of being placed in operation. The required verification is an administrative activity and does not require manipulation of testing of equipment.

E.1

If the Required Actions and associated Completion times of Conditions C or D are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TS 2.1.1.3 Safety Limit. Note that Required Actions D.1, D.2, D.3, and D.4 are also applicable when DRAIN TIME is less than 1 hour.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

This Surveillance verifies that the DRAIN TIME of RPV water inventory to the TS 2.1.1.3 Safety Limit is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a Control Rod RPV penetration flow path with the Control Rod Drive Mechanism removed and not replaced with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used..

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are locked, sealed, or otherwise secured in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining in the event of an Operating Basis Earthquake. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines and ongoing plant maintenance and testing activities.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

The exclusion of penetration flow paths from the determination of DRAIN TIME must consider the potential effects of a single operator error or initiating event on items supporting maintenance and testing (rigging, scaffolding, temporary shielding, piping plugs, snubber removal, freeze seals, etc.). If failure of such items could result and would cause a draining event from a closed system or between the RPV and the isolation device, the penetration flow path may not be excluded from the DRAIN TIME calculation.

Surveillance Requirement 3.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2 and SR 3.5.2.3

The minimum water level of 7.0 ft required for the suppression pool is periodically verified to ensure that the suppression will provide adequate Net Positive Section Head (NPSH) for the LPCI subsystem pump, recirculation volume, and vortex prevention. With the suppression pool water level less that the required limit, the required LPCI subsystem is inoperable.

When suppression pool level is < 8.0 ft, the required CS subsystem is considered OPERABLE only if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CS pump. Therefore, a verification that either the suppression pool water level is ≥ 8.0 ft or that a required CS subsystem is aligned to take suction from the CSTs and the CSTs contain ≥ 75,000 gallons of water, equivalent to 11 ft in one CST or ≥ 7 ft in both CSTs, ensures that the required CS subsystem can supply at least 75,000 gallons of makeup water to the RPV.

This Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.4

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.5

Verifying the correct alignment for power operated and automatic valves in the required ECCS subsystem flow path provides assurance that the proper flow paths will be available for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to manual valves unless the valves are being manipulated to serve as all or part of a system vent flow path opened under administrative control, as described in the SR Note (and Bases paragraph below). In this case, the SR Note allows the licensee to credit administratively controlled manual action to close the system vent flow path in order to maintain system Operability during system venting and performance of the gas accumulation SR. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include a stationing of a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

In Modes 4 and 5, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. Because of the restrictions on

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.5 (continued)

DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TS 2.1.1.3 Safety Limit.

SR 3.5.2.6

Verifying that the required ECCS injection/spray subsystem can be manually started and operate for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. Testing the ECCS injection/spray subsystem through the recirculation line is necessary to avoid overfilling the refueling cavity. The minimum operating time of 10 minutes was based on engineering judgement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.7

Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TS 2.1.1.3 Safety Limit should an unexpected draining event occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.8

The required ECCS subsystem must be capable of being manually operated. This Surveillance verifies that the required ECCS injection/spray subsystem, including the associated pump and valves, can be manually operated.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

(continued)

BASES (continued)

REFERENCES

1. Information Notice 84-81, “Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup,” November 1984.

2. Information Notice 86-74, “Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves,” August 1986.

3. Generic Letter 92-04, “Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f),” August 1992.

4. NRC Bulletin 93-03, “Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs,” May 1993.

5. Information Notice 94-52, “Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1,” July 1994.

6. General Electric Service Information Letter No. 388, “RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6,” February 1983.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following Reactor Pressure Vessel (RPV) isolation accompanied by a loss of coolant flow from the Feedwater System to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC Systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the Feedwater System line, where the coolant is distributed within the RPV through the Feedwater sparger. Suction piping is provided from the Condensate Storage Tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from a main steam line upstream of the associated inboard Main Steamline Isolation Valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures 150 psig to 1120 psig. Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)

The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge piping is kept full of water. The RCIC System is normally aligned to the CST. The height of water in the CST is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep fill" system when its suction is aligned to the CST. When RCIC suction is aligned to the suppression pool and the system is not in operation, an alternate means of keeping the discharge piping full is required to support system OPERABILITY.

APPLICABLE SAFETY ANALYSES

The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an ECCS System, although the RCIC System Operation is credited during Loss of Feedwater events. Based on its contribution to the reduction of overall plant risk, however, the system satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the RCIC System provides adequate core cooling in the event of RPV isolation accompanied by a loss of Feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event. Management of gas voids is important to RCIC System OPERABILITY.

APPLICABILITY

The RCIC System is required to be OPERABLE during MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure $\leq$ 150 psig, the low pressure ECCS injection/spray subsystems can provide sufficient flow to the RPV. In MODES 4 and 5, RCIC is not required to be OPERABLE since RPV water inventory control is required by LCO 3.5.2, “RPV Water Level Inventory Control.”

(continued)

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC System. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC System and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a Loss of Coolant Accident (LOCA). OPERABILITY of HPCI is therefore verified immediately within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified immediately, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of out of service times. Because of similar functions of HPCI and RCIC, the out of service times (i.e., Completion Times) determined for HPCI are also applied to RCIC.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RCIC System and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RCIC System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1 (continued)

may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

SR 3.5.3.2

Verifying the correct alignment for power operated and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time.

This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to manual valves unless the valves are being manipulated to serve as all or part of a system vent flow path opened under administrative control, as described in the SR Note (and Bases paragraph below). In this case, the SR Note allows the licensee to credit administratively controlled manual action to close the system vent flow path in order to maintain system Operability during system venting and performance of the gas accumulation

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.2 (continued)

SR. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of this SR was derived from the INSERVICE TESTING PROGRAM requirements for performing valve testing. The Frequency is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include a stationing of a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Reactor steam pressure must be $\geq$ 940 psig to perform SR 3.5.3.3, the high pressure test, and $\leq$ 160 psig to perform SR 3.5.3.4, the low pressure test. Adequate steam flow is represented by approximately 0.4 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure Surveillance has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable.

Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hour allowance to reach the required pressure and flow is sufficient to achieve stable conditions for testing and provide a reasonable time to complete the SRs.

The Frequency for SR 3.5.3.3 is in accordance with the INSERVICE TESTING PROGRAM. The Surveillance Frequency for SR3.5.3.4 is controlled under the Surveillance Frequency Control Program. The Frequency for SR 3.5.3.4 is based on the need to perform the Surveillance under conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at this Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.5

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on an RPV low water level signal received subsequent to an RPV high water level trip and that the suction is automatically transferred from the CST to the suppression pool on a CST Low Level signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at this Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 3.1.2.4.4.

2. UFSAR, Section 5.4.6.

3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material. The Primary Containment in the General Electric Mark-I containment design consists of a drywell section and a suppression chamber interconnected by a vent pipe system. The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion, the so-called "inverted light bulb" shape, built to the requirements of Section III to the ASME code. The drywell is equipped with hatches and a personnel airlock for equipment and personnel access. The drywell is enclosed in a reinforced-concrete structure for shielding purposes. The pressure suppression chamber is also a Section III steel pressure vessel built in the shape of a torus, which is located below and encircles the drywell. The pressure suppression chamber contains the pressure suppression pool, which serves as the heat sink during Loss-of-Coolant Accidents and other transients in which the primary heat sink (Main Condenser) is lost. The suppression chamber is connected to the drywell via a series of large vent pipes that direct the energy released from the primary reactor system into the suppression pool. The energy can also be directly transferred from the primary reactor system to the suppression pool via the safety/relief valves, High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) turbine exhaust lines.

The isolation devices for the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

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

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Lock"; and

c. All equipment hatches and manways are closed.

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3, 4 and 5), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 2.0% by weight of the containment air per 24 hours at the

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BASES

APPLICABLE SAFETY ANALYSES (continued)

design basis LOCA maximum peak containment pressure (P_a) of 45.7 psig (Ref. 2).

Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq$ 1.0 L_a, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the pressure suppression function is accomplished and the suppression chamber pressure does not exceed design limits. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

In the event primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits (SR 3.6.1.2.1), resilient seal primary containment purge valve leakage limits (SR 3.6.1.3.4), or main steam isolation valve leakage limits (SR 3.6.1.3.9) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $< 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR maintains

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 (continued)

drywell to suppression chamber differential pressure during a 10 minute period to measure and ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and verifying that the increase in suppression chamber pressure is less than 0.009 psi per minute when averaged over a 10 minute period. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency was developed considering it is required that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs.

REFERENCES

1. UFSAR, Section 6.2.

2. UFSAR, Section 15.2.

3. 10 CFR 50, Appendix J, Option B.

4. NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance - Based Option of 10 CFR Part 50, Appendix J."

5. ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirement."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

One double door primary containment air lock has been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. The air lock is designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors contains a single gasketed seal to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in primary containment internal pressure results in increased sealing force on each door).

Each air lock is nominally a right circular cylinder, 12 ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions as allowed by this LCO, the primary containment may be accessed through the air lock, when the interlock mechanism has failed, by manually performing the interlock function.

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analysis.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 2.0% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 45.7 psig (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment.

The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

As part of the primary containment pressure boundary, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the outer door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial measures are taken when necessary, if air lock leakage results in exceeding overall containment leakage rate acceptance criteria. Pursuant to LCO 3.0.6, actions are not required, even if primary containment leakage is exceeding L_a. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3

With one primary containment air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1) in the air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

Required Action A.3 ensures that the air lock penetration has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on TS-required equipment or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during entry and exit, and assuring the OPERABLE door is relocked after completion of the containment entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if the overall air lock leakage is not within limits. In many instances, primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with the overall air lock leakage not within limits, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, Required Action C.3 requires the air lock to be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

Testing of the air lock requires the installation of a strongback on the inner door to keep it closed during testing, since the air lock is tested by pressurizing the space between the inner and outer doors. Without the strongback, the inner door could be forced open by the pressure against it in the non-accident direction. Opening the air lock door to remove the strongback (or other test equipment), does not require further leak testing, as long as the inner door seal is not disturbed.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 requires the results of airlock leakage tests be evaluated against the acceptance criteria of the Primary Containment Leakage Rate Testing Program, 5.5.12. This ensures that the airlock leakage is properly accounted for in determining the combined Type B and C primary containment leakage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the primary containment airlock door is used for entry and exit (procedures require strict adherence to single door opening) and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power, this test is only required to be performed under the conditions that apply during a plant outage. The Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during use of the airlock.

REFERENCES

1. UFSAR, Section 6.2.1.1.
2. 10 CFR 50, Appendix J, Option B.
3. UFSAR, Section 15.2.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary 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 DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment functions assumed in the safety analyses will be maintained. These isolation devices are either passive or active (automatic). Closed manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves and other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system, provided the closed system is sufficiently leak tight to meet the total allowable Primary Containment leakage limits in SR 3.6.1.1.1.

The reactor building-to-suppression chamber vacuum breakers serve a dual function, one of which is primary containment isolation. However, since the primary safety function of the vacuum breakers would not be available if the normal PCIV actions were taken, the PCIV OPERABILITY requirements are not applicable to the reactor building-to-suppression chamber vacuum breakers valves. Similar surveillance requirements in the LCO for reactor building-to-suppression chamber vacuum breakers provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

(continued)

BASES

BACKGROUND (continued)

Other valves, such as torus suction valves and pump minimum flow valves, also serve a dual function. These dual function valves, have both a primary and secondary safety function, the primary function being core cooling and the secondary function being containment isolation. As such, these dual function valves are not subject to the ACTIONS of this LCO (References 6 and 7) and are not included in the valve list in the plant Administrative Control Procedures.

The primary containment purge lines are 18 inches in diameter and the vent lines are also 18 inches in diameter. The 18 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. However, these purge valves may be open when being used for pressure control, inerting, de-inerting, ALARA or air quality considerations. These valves are qualified to be open because an atmospheric relief valve damper (set to actuate at 10 inches water gauge pressure) is installed downstream of the containment vent/purge valves to protect the SBGT System ductwork from overpressure conditions that could be present during certain venting conditions. The inboard isolation valves on the 18 inch vent lines have 2 inch bypass lines around them for use during normal reactor operation.

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBA that results in a release of radioactive material within primary containment is a LOCA. In the analysis for this accident, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in Reference 1, the MSLB is one of the four key events due to radiological consequences at the site boundary. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

to close within 3 to 5 seconds, which is conservative with respect to the 10.5 second closure time assumed in the analysis. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The LOCA analysis assumes that within approximately 120 seconds of the accident, isolation of the primary containment is complete and leakage is terminated, except for the maximum allowable leakage rate, L_a. The primary containment isolation total response time of 120 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times. Isolation valves on process lines that communicate directly with the reactor vessel are required to reach the fully closed position in various times less than 60 seconds in order to limit vessel inventory loss to prevent level from dropping below the top of active fuel (Reference 4).

PCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

Active PCIVs are OPERABLE when power operated, automatic isolation valves have isolation times within limits and actuate on an automatic isolation signal. The passive PCIVs are considered OPERABLE when manual valves are closed (or open in accordance with appropriate administrative controls), automatic valves that are normally closed and de-activated, remain secured in their closed position, and blind flanges are in place. These passive isolation valves and devices are those listed in Reference 2 or in applicable administrative procedures. Note: normally active PCIVs that are made passive by closing and de-activating them are not OPERABLE.

The 18 inch purge valves must be blocked to prevent full opening. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers."

The valves covered by this LCO are listed in the plant Administrative Control Procedures and PCIV stroke times are

(continued)

BASES

LCO (continued)

provided in the INSERVICE TESTING PROGRAM.

Purge valves with resilient seals, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE in MODES 4 and 5. Shutdown Cooling System Isolation valves, however, are required to be OPERABLE in Modes 4 and 5 to prevent inadvertent reactor vessel draindown. These valves are only required to be OPERABLE for those functions required OPERABLE by the associated instrumentation per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." Per Table 3.3.6.1, if RHR Shutdown Cooling System integrity is maintained (i.e., no OPDRVs in progress within the RHR Shutdown Cooling System boundary) only one trip system and its associated PCIVs are required to be OPERABLE in Modes 4 and 5. Specifically, either an inboard trip system and its associated PCIVs (MO-1908 and MO-2003) or the outboard trip system and its associated PCIVs (MO-1909 and MO-1905) must be OPERABLE. (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. For valves requiring local operation, these controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. For valves that can be operated remotely from the control room, the valve hand

(continued)

BASES

ACTIONS (continued)

switch is tagged or controlled per plant procedures, identifying that the valve is open under administrative control and must be closed should an isolation signal occur. In the event of an isolation signal, plant procedures direct control room operators to verify all automatic actions occur, and to manually initiate those automatic actions that should have occurred but did not. This will ensure the control room operators verify any valves open under administrative control close in response to an isolation signal. If any of the open valves are unable or fail to close automatically, the control room operators will manually close them.

Note 1 allows penetrations to be opened for other operational reasons, such as draining, venting, etc.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures that appropriate remedial actions are taken, if necessary, if the affected system(s)/function(s) are rendered inoperable by an inoperable PCIV. Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded due to excessive leakage on any PCIV such that overall containment leakage criteria could be exceeded. Pursuant to LCO 3.0.6, these actions are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for MSIV or purge valve leakage not within limits, the affected penetration flow paths must be isolated in order to permit continued operation. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure, that is, must either be a passive component, or be converted from an active to a passive component. Isolation barriers that meet this criterion are a closed and de-activated

(continued)

BASES

ACTIONS A.1 and A.2 (continued)

automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve, flange, etc., to the primary containment. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. The 18 inch primary containment purge valves are equipped with resilient seals that require compressed air to ensure leak tightness. Therefore, both inboard and outboard 18 inch containment purge valves for the affected penetration are required to have functional resilient seals in order to provide an isolation barrier that cannot be affected by a single active failure. Thus, an acceptable isolation barrier is established when both inboard and outboard purge valves are de-activated in the closed position, with the resilient seals pressurized to ensure leak tightness of both purge valves. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertenly repositioned. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except for MSIV or purge valve leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour in order to permit continued operation. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure, that is, must either be a passive component, or be converted from an active to a passive component. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is

(continued)

BASES

ACTIONS

B.1 (continued)

replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc.

The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

Condition C is applicable to Type C isolation valves (UFSAR Section 6.2.4.2.1.1) in the reactor building closed cooling water (MO-4841A and MO-4841B) and drywell cooling (CV-5718A, CV-5718B, CV-5704A and CV-5704B) systems and is also applicable to excess flow check valves. With one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated in order to permit continued operation.

The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure, that is, must either be a passive component, or be converted from an active to a passive component. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. A check valve may not be used to isolate the affected penetration.

Required Action C.1 must be completed within 72 hours. The Completion Time of 72 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Reference 9.

The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument and the small pipe diameter of

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. For affected penetrations that have been isolated in accordance with Required Action C.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis.

This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1

With one or more penetration flow paths with one or more MSIVs not within leakage limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed

(continued)

BASES

ACTIONS

D.1 (continued)

manual valve, or blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

E.1

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated in order to permit continued operation. The method of isolation must be by the use of at least one isolation barrier that will maintain leak tightness under LOOP-LOCA conditions. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. The specified Completion Time is reasonable, to take the ACTIONS or return the purge valve leakage to within limits, given the low probability of an event during this short period of time.

E.2

If a purge valve with resilient seal is utilized to satisfy Required Action E.1, unlimited operation is not permitted as this method of isolating the penetration is susceptible to single failures that could compromise the leak tightness of the entire penetration (e.g., loss of air compressor, DG failure, etc). Thus, per the Note to Required Action E.2, if this method of isolation is used, the containment purge valve leakage must be restored to within limits within 72 hours. The specified Completion Time is reasonable,

(continued)

BASES

ACTIONS

E.2 (continued)

considering that one containment purge valve remains sealed so that primary containment integrity is maintained, although not single failure tolerant and the low probability of an event occurring during this time period.

Required Action E.2 is modified by a Note indicating this Required Action is only required to be performed if a purge valve with resilient seal is used to satisfy Required Action E.1. If the method of isolation is by the use of at least one isolation barrier that cannot be adversely affected by a single active failure, then Required Action E.2 is not required because the integrity of the affected penetration flow path is being maintained by a passive device and unlimited operation is permitted.

E.3

In accordance with Required Action E.3, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Required Action E.3 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR 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.

If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is 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, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency was chosen to provide added assurance that the purge valves are in the correct position.

(continued)

BASES

SUREVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.2

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.3

Verifying the isolation time of each power operated automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.5. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the requirements of the INSERVICE TESTING PROGRAM.

SR 3.6.1.3.4

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B (Ref. 3), is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between primary containment and the environment), a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.4 (continued)

corresponding Surveillance Frequency. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The purge system isolation valves are tested in three groups, by penetration: drywell purge exhaust group (CV-4302 and CV-4303), torus purge exhaust group (CV-4300 and CV-4301), and drywell/torus purge supply group (CV-4307, CV-4308 and CV-4306). If the results of a combined leak rate or pressure drop test indicate excessive leakage, credit can be taken for one of the purge valves to satisfy Required Action E.1, if it can be reasonably determined that the purge valve to be credited for isolation is not leaking excessively.

Additionally, this SR must be performed once within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened.) Thus, decreasing the normal Surveillance interval is a prudent measure after a valve has been opened.

SR 3.6.1.3.5

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 50.67 limits and that the core remains covered. The Frequency of this SR is in accordance with the requirements of the INSERVICE TESTING PROGRAM.

SR 3.6.1.3.6

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. A Note has been added for the MSIVs, that allows this SR to be met by any series of sequential, overlapping, or total steps so that proper operation of the MSIVs on receipt of an actual or simulated isolation signal is verified. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would eliminate cooling water flow and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.6 (continued)

disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this Surveillance when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.7

This SR requires a demonstration that a representative sample of reactor instrumentation line Excess Flow Check Valves (EFCVs) are OPERABLE by verifying that the valves cause a marked decrease in flow rate on a simulated instrument line break. This SR provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during the postulated instrument line break event evaluated in Reference 5. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested at least once every 10 years (nominal). The nominal 10 year interval is based on other performance-based testing programs, such as inservice testing (snubbers) and Option B to 10 CFR 50, Appendix J. EFCV test failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. 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 (Reference 10).

SR 3.6.1.3.8

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. Other administrative controls, such as those that limit the shelf life of the explosive charges, must also be followed. The Frequency of this SR is in accordance with the requirements of the INSERVICE TESTING PROGRAM.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.9

The analysis in Reference 8 is based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be $\leq$ 100 scfh when tested at $\geq$ 24 psig. The combined maximum Main Steam pathway leakage rate for all four main steam lines (including the inboard MSIV drain line) must be $\leq$ 200 scfh when tested at $\geq$ 24 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The frequency is required by the Primary Containment Leakage Rate Testing Program.

REFERENCES

1. UFSAR, Chapter 15.2.
2. UFSAR, Table 7.3-1.
3. 10 CFR 50, Appendix J, Option B.
4. UFSAR, Section 7.3.1.1.1.7.
5. UFSAR, Section 1.8.11.
6. J. Franz (IELP) to T. Murley (NRC), “Revised Response to NRC Position on Operability of Safety-Related Dual Function Valves,” NG-93-5124, December 7, 1993.
7. G. Kelly (NRC) to L. Liu (IES), “NRC Position on Operability of Safety-Related Dual Function Valves at the Duane Arnold Energy Center (TAC No. 88398),” January 3, 1995.
8. UFSAR Section 6.7.4.3
9. UFSAR Section 3.1.2.5
10. GE BWROG B21-00658-01, “Excess Flow Check Valve Testing Relaxation,” dated November 1998.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Air Temperature

BASES

BACKGROUND

The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for a spectrum of break sizes for postulated Loss of Coolant Accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 1). Analyses assume an initial average drywell air temperature of 135°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 340°F(Ref. 2). Both the maximum allowable temperature (340°F) and the peak (DBA) drywell temperature (292.9°F) exceed the drywell design temperature (281°F). This is acceptable since a generic analysis conducted for a similar drywell demonstrates that the higher temperatures can be tolerated with no significant compromise to the original design margins. Exceeding the maximum allowable temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident.

Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the drywell design temperature. As a result, the ability of primary containment to perform its design function is ensured.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

If the drywell average air temperature cannot be restored to within limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. Drywell air temperature is monitored in all quadrants and at various elevations (referenced to mean sea level). Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.

REFERENCES

1. UFSAR, Section 15.0.

2. UFSAR, Section 15.2.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Low-Low Set (LLS) Valves

BASES

BACKGROUND

The Safety Relief Valves (SRVs) can actuate in either the safety mode, relief mode (manual), the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the pilot valve. As in the safety mode, opening the pilot valve allows a differential pressure to develop across the main valve piston and opens the main valve. The main valve can stay open with valve inlet steam pressure as low as 50 psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the pilot valves. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.

Two of the SRVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure after reactor pressure has exceeded the scram setpoint and any SRV has opened at its normal steam pilot setpoint, and stay open longer, so that reopening more than one SRV is prevented on subsequent actuations. This mitigates the induced loads on the containment and the thrust loads on the SRV discharge lines by increasing the time between subsequent SRV actuations. Therefore, the LLS function prevents excessive short duration SRV cycles that would occur with valve actuation at the relief setpoint.

Each SRV discharges steam through a discharge line and T-quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower containment load.

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of one SRV operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of SRVs (following the initial opening), and the corresponding higher loads,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

are avoided. However, this design feature is not critical since simultaneous valve opening is not a concern for Mark I containment, and since simultaneous opening will not cause water swell problems for a BWR (Ref. 3). The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the SRV discharge line resulting from "subsequent actuations" of the SRV during major pressure transients such as MSIV closure or turbine trip without bypass. Furthermore, the LLS function justifies the primary containment analysis assumption that simultaneous SRV openings occur only on the initial actuation for Limiting Transients.

LLS valves satisfy Criterion 3 10 CFR 50.36(c)(2)(ii).

LCO

Two LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analyses (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the SRVs.

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of SRVs. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the LLS valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one LLS valve inoperable, the remaining OPERABLE LLS valve is adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS valve and the low probability of an event in which the remaining LLS valve capability would be inadequate.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If both LLS valves are inoperable or if the inoperable LLS valve cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

The actuator of each LLS dual function safety/relief valves (S/RVs) is stroked to verify that the pilot valve strokes when manually actuated. For the S/RVs, the actuator test is performed by energizing a solenoid that pneumatically actuates a plunger. The plunger is connected to the second stage disc located within the main valve body. When steam pressure actuates the plunger during plant operation, this allows pressure to be vented from the top of the main valve piston, allowing reactor pressure to lift the main valve piston, which opens the main valve disc. The test will verify movement of the plunger in accordance with vendor recommendations. However, since this test is performed prior to establishing the reactor pressure needed to overcome main valve closure forces, the main valve disc will not stroke during the test.

This SR, together with the valve testing performed as required by the ASME Code for pressure relieving devices (ASME OM Code - 2001 through 2003 Addenda), verify the capability of each relief valve to perform its function.

Valve testing will be performed at a steam test facility, where the valve (i.e., main valve and pilot valve) and an actuator representative of the actuator used at the plant will be installed on a steam header in the same orientation as the plant installation. The test conditions in the test facility will be similar to those in the plant installation, including ambient temperature, valve insulation, and steam conditions. The valve will then be leak tested, functionally tested to ensure the valve is capable of opening and closing (including stroke time), and leak tested a final time. Valve seat tightness will be verified by a cold bar test, and if not free of fog, leakage will be measured and verified to be below design

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1 (continued)

limits. In addition, for the safety mode of S/RVs, an as-found setpoint verification and as-found leak check are performed, followed by verification of set pressure, and delay time. The valve will then be shipped to the plant without any disassembly or alteration of the main valve or pilot valve components.

The combination of the valve testing and the valve actuator testing provide a complete check of the capability of the valves to open and close, such that full functionality is demonstrated through overlapping tests, without cycling the valves.

The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.1.5.2

The LLS designated SRVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.3, "Low-Low Set (LLS) Instrumentation," overlaps this SR to provide complete testing of the safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

REFERENCES

1. UFSAR, Section 5.4.13.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

3. NEDE-30021-P, Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for DAEC, January 1983.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the two reactor building-to-suppression chamber vacuum breaker assemblies is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breaker assemblies and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief system consists of two vacuum breaker assemblies each consisting of a vacuum breaker and an air operated butterfly valve, located in series in each of two branch lines from a single penetration through the reactor building to a common line that penetrates the suppression chamber airspace. The butterfly valve is actuated by differential pressure and can be remotely operated. The vacuum breaker is self actuating and can be locally operated for testing purposes. Both the butterfly valve and the vacuum breaker valve of each vacuum breaker assembly must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breaker assemblies prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breaker assemblies.

The external vacuum breaker assemblies are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum

(continued)

BASES

BACKGROUND (continued)

negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the reactor building-to-suppression chamber vacuum breaker assemblies are presented in Reference 1 as part of the accident response of the containment systems. Internal vacuum breakers (suppression-chamber-to-drywell) and external vacuum breaker assemblies (reactor building-to-suppression chamber) are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breaker assembly valves to be closed initially and to be fully open at 0.5 psid (Ref. 1). Additionally, of the two reactor building-to-suppression chamber vacuum breaker assembly valves, one is assumed to fail in a closed position to satisfy the single active failure criterion. Design Basis Accident (DBA) analyses require the vacuum breaker assembly valves to be closed initially and to remain closed and leak tight with positive primary containment pressure.

The adequacy of the external vacuum breaker assemblies was determined by considering an inadvertent containment spray operation while the drywell is at the 150°F maximum operating temperature and at a pressure slightly greater than 2 psig.

The results of this evaluation shows that the external vacuum breaker assemblies, with an opening setpoint of 0.5 psid, are capable of maintaining the differential pressure within design limits.

The reactor building-to-suppression chamber vacuum breaker assemblies satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Both reactor building-to-suppression chamber vacuum breaker assemblies are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that both vacuum breaker assembly valves (vacuum breaker and air operated butterfly valve) in each of the two branch lines from the reactor building to the common line that penetrates the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, the requirement ensures both vacuum breaker assembly valves in each branch line will open to relieve a negative pressure in the suppression chamber.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 1, 2, and 3, Suppression Pool Spray System operation may be desirable to mitigate the effects of a DBA. Excessive negative pressure inside primary containment could occur due to inadvertent initiation of this system. Therefore, the vacuum breaker assemblies are required to be OPERABLE in MODES 1, 2, and 3, when Suppression Pool Spray System operation may be desirable, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.

Also, in MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. This event results in a rapid depressurization of the drywell, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining reactor building-to-suppression chamber vacuum breaker assemblies OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration branch line flow path.

A.1

With one or two vacuum breaker assemblies with one valve not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable vacuum breaker assembly valve(s) must be restored to OPERABLE status or the open vacuum breaker assembly valves closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression chamber-to-drywell vacuum breakers in LCO 3.6.1.7, "Suppression Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining vacuum breaker assembly valves, the fact that the OPERABLE vacuum breaker assembly valve in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breaker assembly valves to be OPERABLE during this period.

B.1

With one or two vacuum breaker assemblies with two vacuum breaker assembly valves not closed, primary containment integrity is not maintained. Therefore, one open vacuum breaker assembly valve per line must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

C.1

With one vacuum breaker assembly with one or more vacuum breaker assembly valves inoperable for opening, but known to be closed, the leak tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened, however, if both vacuum breaker assembly valves in at least one vacuum breaker assembly are not OPERABLE.

(continued)

BASES

ACTIONS

C.1 (continued)

Therefore, the inoperable vacuum breaker valve assembly must be restored to OPERABLE status within 72 hours. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

D.1

With two vacuum breaker assemblies with one or more vacuum breaker assembly valves inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breaker assemblies is lost. Therefore, all vacuum breaker assembly valves in one vacuum breaker assembly must be restored to OPERABLE status within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Each vacuum breaker assembly valve is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker assembly valve position or by verifying a differential pressure of 0.5 psid is maintained between the reactor building and suppression chamber. If the position indicator of any vacuum breaker assembly valve is inoperable, plant procedures require the position indicator to be restored or the affected vacuum

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

breaker assembly valve be periodically verified to be closed by visual inspection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker assembly valve status available to operations personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. The first Note allows reactor building-to-suppression chamber vacuum breaker assembly valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breaker assembly valves are controlled by plant procedures and do not represent inoperable vacuum breaker assembly valves. The second Note is included to clarify that vacuum breaker assembly valves open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.6.2

Each vacuum breaker assembly valve must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of this SR was developed based upon INSERVICE TESTING PROGRAM requirements for performing valve testing.

SR 3.6.1.6.3

Demonstration of vacuum breaker assembly valve opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker assembly valve full open differential pressure of $\leq$ 0.614 psid is valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based upon the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 6.2.1.1.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression-chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 7 internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow noncondensible gasses from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled reflood water flowing out of a postulated break in the primary system. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, noncondensible gasses in the drywell are purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a primary system break, or drywell spray actuation following a Loss of Coolant Accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is less than the suppression

(continued)

BASES

BACKGROUND (continued)

chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the waterleg in the vent system during normal operation.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Internal (suppression chamber-to-drywell) and external (reactor building- to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary.

The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 0.5 psid (Ref. 2). Additionally, 1 of the 7 internal vacuum breakers is assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setting is a result of the requirement placed on the vacuum breakers to prevent excessive water-level variations in the submerged portion of the vent downcomer lines. The vacuum breaker capacity, with one of the valves failed, is adequate to limit the pressure differential between the suppression chamber and the drywell during post accident drywell cooling operations to a value that is within the suppression chamber design values.

The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Only 6 of the 7 vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers, however, are required to be closed (except during testing,

(continued)

BASES

LCO (continued)

inerting or de-inerting containment or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

APPLICABILITY

In MODES 1, 2, and 3, Containment Spray System operation may be desirable to mitigate the effects of a DBA. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3, when the Containment Spray System may be operated, to mitigate the effects of inadvertent actuation of the Containment Spray System.

Also, in MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of noncondensible gases and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

With one of the required vacuum breakers inoperable for opening (e.g., the vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining five OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive suppression chamber - to-drywell differential pressure during a DBA. Therefore, with one of the six required vacuum breakers inoperable, 72 hours is allowed to restore at least one of the inoperable vacuum breakers to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

B.1

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a drywell to suppression chamber differential pressure of 0.5 psid is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test.

C.1 and C.2

If the inoperable suppression chamber-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified closed (except when performing its intended function as stated in LCO 3.6.1.7) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. Each vacuum breaker is equipped with two closed position indicators. One position indicator indicating closed is sufficient to verify the vacuum breaker is closed. However, if one closed position indicator is found to be inoperable, actions should be initiated to restore it to OPERABLE status, if possible. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

A Note is added to this SR which allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

SR 3.6.1.7.2

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of this SR was developed, based on INSERVICE TESTING PROGRAM requirements

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.2 (continued)

for performing valve testing. The Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE, since they are located in a harsh environment (the suppression chamber airspace).

SR 3.6.1.7.3

Verification of the vacuum breaker opening setting is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.5 psid is valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. The Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. UFSAR, Section 6.2.1.1.2.5.
2. UFSAR, Section 6.2.1.4.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the downcomer lines during a Loss of Coolant Accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from steam exhaust lines in the turbine driven systems (i.e., the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation — the original limit for the end of a LOCA blowdown was 170°F, based on the Bodega Bay and Humboldt Bay Tests; and,

b. Primary containment peak pressure and temperature — design pressure is 56 psig and design temperature is 281°F (Ref. 1).

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1.) An initial pool temperature of 95°F is assumed for the Reference 1 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool temperature of 120°F are assumed for the containment loads analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Suppression Pool Average Temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are:

a. Average temperature $\leq$ 95°F when any OPERABLE intermediate range monitor (IRM) channel is $>$ 25/40 divisions of full scale on Range 7 and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature $\leq$ 105°F when any OPERABLE IRM channel is $>$ 25/40 divisions of full scale on Range 7 and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to $\leq$ 95°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is $>$ 95°F is short enough not to cause a significant increase in plant risk.

c. Average temperature $\leq$ 110°F when all OPERABLE IRM channels are $\leq$ 25/40 divisions of full scale on Range 7. This requirement ensures that the plant will be shut down at $>$ 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

(continued)

BASES

LCO (continued)

Note that 25/40 divisions of full scale on IRM Range 7 while not the only indication available, was chosen as a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP. At this power level, heat input is approximately equal to normal system heat losses, i.e., the "point of adding heat".

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when THERMAL POWER is $>$ 1% RTP, the initial conditions exceed the conditions assumed for the Reference 1, 2, and 4 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool average temperature to be restored below the limit. Additionally, when suppression pool temperature is $>$ 95°F, increased monitoring of the suppression pool temperature is required to ensure that it remains $\leq$ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed.

Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room to alert the operator to an abnormal suppression pool average temperature condition.

(continued)

BASES

ACTIONS (continued)

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the power must be reduced to < 25/40 divisions of full scale on Range 7 for all OPERABLE IRMs within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be > 95°F when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7 and when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2, and D.3

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the Shutdown position. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown position is permitted by the definition of an Immediate Completion Time. Further cooldown to MODE 4 is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when suppression pool temperature is > 110°F, increased monitoring of pool temperature is required to ensure that it remains ≤ 120°F. The once per 30 minute Completion Time is adequate, based on operating experience.

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Given the high suppression pool average temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained at $\leq$ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours, and the plant must be brought to at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure post-LOCA. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk suppression pool temperature could be exceeded very quickly and possibly exceed the allowable loads on the Torus.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1 (continued)

The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. UFSAR, Section 6.2.
2. UFSAR, Section 15.0.
3. [Deleted]
4. DAEC Plant Unique Analysis Report (PUAR), June 1983.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from Safety/Relief Valve (SRV) discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the downcomer lines during a Loss of Coolant Accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the steam exhaust lines in the turbine driven systems (i.e., High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System) and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 58,900 ft^3 at the low water level limit of 10.11 ft and 61,500 ft^3 at the high water level limit of 10.43 ft.

If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the SRV T-quenchers, vent system downcomer pipes, or HPCI and RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate Net Positive Suction Head (NPSH) to the Emergency Core Cooling System Pumps. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified.

If the suppression pool water level is too high, it could result in excessive clearing loads from SRV discharges and excessive pool swell loads during a DBA LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to SRV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

Suppression Pool Water Level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

A limit that suppression pool water level be $\geq$ 10.11 ft and $\leq$ 10.43 ft is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation.

The level requirements also ensure that downcomer submergence is sufficient to ensure condensation effectiveness and prevent steam bypass to the suppression chamber air space and that loads and structural integrity are acceptable.

APPLICABILITY

In MODES 1, 2, and 3, a DBA would cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "RPV Water Inventory Control."

(continued)

BASES (continued)

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as vent system downcomer pipes are covered, HPCI and RCIC turbine exhausts are covered, and SRV T-quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of this SR was developed considering operating experience related to trending variations in suppression pool water level and water level instrument drift during the applicable MODES and to assessing the proximity to the specified LCO level limits. Furthermore, the Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.

(continued)

BASES (continued)

REFERENCES 1. UFSAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling (SPC) System can be used to remove heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR-SPC subsystem contains two RHR pumps and one heat exchanger and is manually initiated and independently controlled. The two subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink.

The heat removal capability of one RHR pump in one subsystem is sufficient to meet the overall DBA pool cooling requirement for Loss of Coolant Accidents (LOCAs)(Ref. 1). However, the Anticipated Transient Without Scram (ATWS) analyses that were performed to verify that the suppression pool temperature design limit is not exceeded, contained an assumption that one RHR loop was in operation, with 2 RHR pumps operating to provide a total of 9600 gpm of suppression pool cooling flow. As a result, two RHR pumps are required to support Operability of a RHR Suppression Pool Cooling subsystem. SRV leakage and High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature during or following such events.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when both of the RHR pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Cooling System OPERABILITY.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

With one RHR pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this Condition, the remaining OPERABLE RHR pumps are adequate to perform the RHR Suppression Pool Cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in the system capacity being less than that assumed in the safety analysis (i.e., the valve won't open in the OPERABLE subsystem) for RHR Suppression Pool Cooling capability. The 30 day Completion Time is based on the remaining RHR-SPC heat removal capability and the low probability of a DBA with concurrent worst case single failure.

B.1

With one RHR pump inoperable in each RHR Suppression Pool Cooling subsystem, if no additional failures occur in the RHR Suppression Pool Cooling System, then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA or following any transient that results in a suppression pool temperature rise. However, an additional single failure in the RHR System could reduce the system capacity below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the remaining RHR-SPC heat removal capability and on engineering judgment, considering the level of redundancy provided.

C.1

With one RHR Suppression Pool Cooling subsystem inoperable for reasons other than Condition A (e.g., both pumps inoperable or flowpath inoperable), the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR Suppression Pool Cooling subsystem is

(continued)

BASES

ACTIONS

C.1 (continued)

adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR Suppression Pool Cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

D.1

With two RHR Suppression Pool Cooling subsystems inoperable for reasons other than Condition B (e.g., both subsystems with an inoperable flowpath, or one subsystem with two inoperable pumps and one subsystem with one inoperable pump), one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying by administrative means the correct alignment for manual, power operated and automatic valves in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.3.2

Verifying that each RHR pump develops a flow rate $\geq$ 4800 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that the primary containment peak pressure and temperature and the local suppression pool temperature can be maintained below design limits. This test also verifies that pump performance has not degraded during the surveillance interval. Flow is a normal test of centrifugal pump performance required by ASME Code (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice testing confirms component OPERABILITY, trends performance, and detects incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.2.3.3

RHR Suppression Pool Cooling System piping and components

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.3 (continued)

have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR Suppression Pool Cooling subsystems and may also prevent a water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Suppression Pool Cooling System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Suppression Pool Cooling System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.3 (continued)

accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

DAEC's nine-month response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat removal, and Containment Spray Systems," stated that RHR Suppression Pool Cooling System piping was not susceptible to gas intrusion when in standby readiness. Due to the lack of susceptibility to gas intrusion, SR 3.6.2.3.3 is not performed on a regularly scheduled basis. However, DAEC's response also stated that, based on DAEC specific operating experience, one of the primary mechanisms for potential gas intrusion in the Generic Letter subject systems/functions is incomplete post-maintenance fill and vent activities. Consequently, SR 3.6.2.3.3 will be performed following post maintenance fill and vent activities for RHR Suppression Pool Cooling piping to demonstrate the system is sufficiently fill with water to ensure RHR Suppression Pool Cooling operability.

REFERENCES

1. UFSAR, Section 15.2.1.1.

2. UFSAR, Section 6.2.2.2.1

3. ASME Code for Operation and Maintenance of Nuclear Power Plants

4. Letter, R. Anderson (FPL Energy Duane Arnold) to NRC, Nine-Month Response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems," NG-08-0777, October 13, 2008.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

BASES

BACKGROUND

The suppression pool is designed to absorb the sudden input of heat from the primary system from a Design Basis Accident (DBA) or a rapid depressurization of the reactor pressure vessel (RPV) through the Safety Relief Valves. The primary means provided to remove heat from the suppression chamber is the RHR Suppression Pool Cooling System. Steam blowdown from a DBA can bypass the suppression pool and end up in the suppression chamber airspace as a result of the allowable leakage between the Drywell and Suppression Chamber. Although not required by the accident analysis to ensure that the suppression chamber remains within the analyzed design pressure and temperature limits, condensing the steam in the suppression chamber airspace reduces the long-term pressure response in the primary containment. This support function is provided by two redundant RHR suppression pool spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR suppression pool spray subsystems contains two RHR pumps, which are manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool through the associated piping and returning it to a common suppression pool spray sparger. The sparger only accommodates a small portion of the total RHR pump flow; the remainder of the flow returns to the suppression pool through the suppression pool cooling return line. Thus, both suppression pool cooling (if the RHR heat exchangers and the RHR Service Water System are operated) and suppression pool spray (performed by the spray headers) functions are performed when the Suppression Pool Spray System is initiated. Either RHR suppression pool spray subsystem is sufficient to condense the steam from small bypass leaks from the drywell to the suppression chamber airspace during the postulated DBA.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break loss of coolant accidents. These analyses demonstrate that the pressure reduction capacity of the RHR Suppression Pool Spray System is not required to maintain the primary containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit even without the use of RHR Suppression Pool Spray.

The RHR Suppression Pool Spray is retained in the conversion from the DAEC Technical Specifications to the Improved Technical Specifications (ITS)(see Reference 2), because this function was found to satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii) during the development of NUREG-1433.

LCO

One RHR suppression pool spray subsystem should be available to assist with any potential bypass leakage (Ref. 1). To ensure that this back-up capability is available, two RHR suppression pool spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, at least one subsystem will be OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one of the pumps and associated piping (including spargers), valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Spray System OPERABILITY.

APPLICABILITY

In MODES 1, 2, and 3, the reactor is pressurized and could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR suppression pool spray subsystems OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RHR suppression pool spray subsystem is still available as a back-up to assist with any primary containment bypass leakage. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced capability. The 30 day Completion Time was chosen in light of the back-up nature of this function, the redundant RHR suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring during this period.

B.1

With both RHR suppression pool spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a loss of the back-up capability to deal with any primary containment bypass leakage. The 8 hour Completion Time is based on this loss of back-up capability and is considered acceptable due to the low probability of an event and because the primary methods to remove heat from primary containment are still available.

C.1 and C.2

If the inoperable RHR suppression pool spray subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying that the spray header and nozzles are unobstructed assures that the suppression pool airspace can be sprayed when desired. An air test is specified as this test is generally performed on both the drywell and suppression pool spray nozzles at the same time and it is not desirable to spray water into the drywell, due to the adverse impact on equipment located there.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from the reliability standpoint.

SR 3.6.2.4.2

RHR Suppression Pool Spray System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR Suppression Pool Spray subsystem and may also prevent a water hammer and pump cavitation.

Selection of RHR Suppression Pool Spray System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Suppression Pool Spray System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Suppression Pool Spray System is not

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.2 (continued)

rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Spray System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

DAEC's nine-month response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat removal, and Containment Spray Systems," stated that RHR Suppression Pool Cooling Spray piping was not susceptible to gas intrusion when in standby readiness. Due to the lack of susceptibility to gas intrusion, SR 3.6.2.4.2 is not performed on a regularly scheduled basis. However, DAEC's response also stated that, based on DAEC specific operating experience, one of the primary mechanisms for potential gas intrusion in the Generic Letter subject systems/functions is incomplete post-maintenance fill and vent activities. Consequently, SR 3.6.2.4.2 will be performed following post maintenance fill and vent activities for RHR Suppression Pool Spray piping to demonstrate the system is sufficiently fill with water to ensure RHR Suppression Pool Spray operability.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 15.2.1.

2. UFSAR, Section 6.2.2.3

3. NG-98-0342, J. Franz (IES) to U.S. NRC, “Request for Technical Specification Change (RTS-291): Revision E to the Duane Arnold Energy Center Improved Technical Specifications,” February 26, 1998.

4. Letter, R. Anderson (FPL Energy Duane Arnold) to NRC, Nine-Month Response to NRC Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” NG-08-0777, October 13, 2008.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Containment Atmosphere Dilution (CAD) System

BASES

Deleted

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

The Reference 1 Final Rule removed the definition of a design-basis LOCA hydrogen release and eliminated requirements for hydrogen control systems to mitigate such a release at currently-licensed nuclear power plants. However, the supporting analysis for this rulemaking concluded that combustible gases produced by beyond design-basis accidents, involving both fuel-cladding oxidation and core-concrete interaction, would be risk significant for plants with Mark I and II containments if not for the inerted containment atmosphere. Given the relatively small volume and large zirconium inventory, these containments, without inerting, would have a high likelihood of failure from hydrogen combustion due to the potentially large concentration of hydrogen that a severe accident could cause. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. Thus, the Final Rule required plants with Mark I and II containments to maintain the containment atmosphere with a low concentration of oxygen (i.e., < 4.0 v/o), rendering it inert to combustion.

APPLICABLE SAFETY ANALYSES

The Reference 1 evaluation assumes that the primary containment is inerted when an event with significant core damage occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of degraded core conditions is not likely to produce combustible gas mixtures in the primary containment.

Primary Containment Oxygen Concentration satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that a beyond-design basis event that can produce significant amounts of hydrogen does not result in a combustible mixture inside primary containment.

(continued)

BASES (continued)

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is $< 15\%$ RTP, the potential for an event that generates significant hydrogen is low and the primary containment need not be inerted. Furthermore, the probability of an event that generates significant amounts of hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting. During reactor startups, a convenient and conservative start time for reducing primary containment oxygen concentration to less than 4.0 v/o within 24 hours occurs when the mode switch is placed in Run. Similarly, during reactor shutdowns, limiting the time oxygen can exceed 4.0 v/o to 24 hours prior to taking the mode switch out of Run is also conservative.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

The primary containment must be determined to be inert by verifying that oxygen concentration is < 4.0 v/o. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (control room alarms for containment high oxygen concentration, excessive cycling of the Containment Nitrogen Makeup System or unexplained changes in containment pressure). Indication of abnormal conditions would lead to more frequent monitoring of primary containment oxygen concentration. Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. Federal Register Notice 68 FR 54123, Combustible Gas Control in Containment, Final Rule, dated September 16, 2003.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SBGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves/Dampers (SCIV/Ds)," and LCO 3.6.4.3, "Standby Gas Treatment (SBGT) System."

APPLICABLE SAFETY ANALYSES

The DBA Loss of Coolant Accident (LOCA) takes credit for secondary containment OPERABILITY (Ref. 1). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated by the SBGT System prior to discharge to the environment.

Secondary Containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume.

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

Verifying that secondary containment equipment hatches (e.g., the Refueling Floor roof hatch and the HPCI/RCIC room roof hatches) are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur and provides adequate assurance that exfiltration from the secondary containment will not occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.2

Verifying that one secondary containment access door in each access opening is closed provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. In some cases, secondary containment access openings are shared such that there are multiple inner or outer doors. The intent is to not breach secondary containment, which is achieved by maintaining the inner and outer portion of the barrier closed except when the access opening is being used for entry and exit.

SR 3.6.4.1.2 is modified by a Note that applies to doors located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these doors, once they have been verified to be in the proper position, is low.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.1.3

The SBGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. SR 3.6.4.1.3 demonstrates that one SBGT subsystem can maintain $\geq$ 0.25 inches of vacuum water gauge under calm wind conditions (i.e., less than 15 mph wind speed) at a flow rate $\leq$ 4000 cfm. This cannot be accomplished if the secondary containment boundary is not intact. Therefore, this test is used to ensure secondary containment boundary integrity. Since this SR is a secondary containment test, it need not be performed with each SBGT subsystem. The SBGT subsystems are tested on an alternating basis, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SBGT subsystem will perform this test, and also to ensure that the secondary containment remains sufficiently leak tight, even with a worst case single failure present (i.e., a lockout relay failure that results in either all of the inboard or all of the outboard SCIV/Ds failing to close). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency.

Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES 1. UFSAR, Section 15.2.1.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves/Dampers (SCIV/Ds)

BASES

BACKGROUND

The function of the SCIV/Ds, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary and subsequently processed through SBGT.

The OPERABILITY requirements for SCIV/Ds help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices.

Automatic SCIV/Ds close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or which are related during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment. Two barriers are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation and possibly loss of secondary containment OPERABILITY.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The SCIV/Ds must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accident for which the secondary containment boundary is required is a loss of coolant accident (Ref. 1). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIV/Ds is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SBGT) System before being released to the environment.

Maintaining SCIV/Ds OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SBGT System prior to discharge to the environment.

SCIV/Ds satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

SCIV/Ds form a part of the secondary containment boundary. The SCIV/D safety function is related to control of offsite radiation releases resulting from DBAs.

Active SCIV/Ds, i.e., power operated, automatic SCIV/Ds, are considered OPERABLE when their isolation times are within limits and the SCIV/Ds actuate on an automatic isolation signal. A controlled list of Secondary Containment Automatic Isolation Valves/Dampers covered by this LCO, along with their associated stroke times, are listed in Plant Administrative Procedures.

The passive SCIV/Ds are considered OPERABLE when manual valves are closed (or open in accordance with appropriate administrative controls), automatic SCIV/Ds that are normally closed and de-activated, remain secured in their closed position, and blind flanges are in place. A blind flange (e.g., a utility penetration) may be opened, in accordance with applicable administrative procedures, if the secondary containment negative pressure surveillance is performed with an equivalent (or larger) penetration open, with secondary containment still considered OPERABLE. NOTE: normally active SCIV/Ds that are made passive by closing and de-activating them are not OPERABLE.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIV/Ds is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIV/Ds OPERABLE is not required in MODE 4 or 5.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. For isolation devices requiring local operation, these controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. For isolation devices that can be operated remotely from the control room, the isolation device handswitch is tagged per plant procedures, identifying that the isolation device is open under administrative control and must be closed should an isolation signal occur. In the event of an isolation signal, plant procedures direct control room operators to verify all automatic actions occur, and to manually initiate those automatic actions that should have occurred but did not. This will ensure the control room operators verify any isolation devices open under administrative control close in response to an isolation signal. If any of the open isolation devices are unable or fail to close automatically, the control room operators will manually close them.

Note 1 also expands upon the allowance of LCO 3.0.5, which would only allow the penetration to be opened for testing, by allowing the penetration to be opened for other operational reasons, such as draining, venting, etc. The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition

(continued)

BASES

ACTIONS (continued)

provide appropriate compensatory actions for each inoperable SCIV/D. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIV/Ds are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV/D.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV/D inoperable, the affected penetration flow path(s) must be isolated in order to permit continued operation. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure, that is, must either be a passive component, or be converted from an active to a passive component. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV/D, a closed manual valve, or a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment that meets the applicable engineering design requirements, such as seismic. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and the probability of a DBA, which requires the SCIV/Ds to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Required Action A.2 is modified by two Notes. Note 1 applies to devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIV/Ds in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours in order to permit continued operation. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure, that is, must either be a passive component, or be converted from an active to a passive component. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, or a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIV/Ds to close, occurring during this short time, is very low.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves/dampers. This clarifies that only Condition A is entered if one or more penetration flow paths with one SCIV/D is inoperable.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours.

(continued)

BASES (continued)

ACTIONS

C.1 and C.2 (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

Verifying that the isolation time of each power operated automatic SCIV/D is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV/D will isolate in a time period less than or equal to that assumed in the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.2.2

Verifying that each automatic SCIV/D closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or which are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment. This SR ensures that each automatic SCIV/D will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES 1. UFSAR, Section 15.2.1.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SBGT) System

BASES

BACKGROUND

The SBGT System is required by the UFSAR (Ref. 1). The function of the SBGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SBGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A demister or moisture separator;

b. A prefilter;

c. A High Efficiency Particulate Air (HEPA) filter;

d. A charcoal adsorber;

e. A second HEPA filter; and

f. A centrifugal fan.

HEPA filters are installed before and after the charcoal adsorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment. The in-place testing of the HEPA filters and charcoal adsorbers is performed under the DAEC Ventilation Filter Testing Program (ITS 5.5.7). If the efficiencies of the HEPA filters and charcoal adsorbers are as specified, the resulting doses will be less than the 10 CFR 50.67 guidelines for the accidents analyzed, as the UFSAR Section 15.2.1 for the loss-of-coolant accident shows compliance with 10 CFR 50.67

(continued)

BASES

BACKGROUND (continued)

guidelines with an assumed efficiency of 99% for the adsorber. Operation of the fans significantly different from the design flow envelope will change the removal efficiency of the HEPA filters and charcoal adsorbers.

The sizing of the SBGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. The internal pressure of the SBGT System boundary region is maintained at a negative pressure of at least 0.25 inches water gauge (as determined by averaging pressure readings from different faces of the Secondary Containment boundary) when the system is in operation, which represents an internal pressure that ensures zero exfiltration of air from the building when exposed to calm wind conditions ($<$ 15 mph). Maintaining a negative pressure of 0.25 inches water gauge under calm wind conditions ensures a negative pressure under worst case conditions. Therefore, a negative pressure of 0.25 inches water gauge includes some margin to a negative pressure that ensures zero exfiltration.

The demister is provided to remove entrained water in the air (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SBGT System automatically starts and operates in response to secondary containment isolation actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both charcoal filter train fans start. Upon verification that both subsystems are operating, the redundant subsystem is normally shut down.

APPLICABLE SAFETY ANALYSES

The design basis for the SBGT System is to mitigate the consequences of a loss of coolant accident (Ref. 3). For all events analyzed, the SBGT subsystem is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment. Only one of the two SBGT subsystems is needed to clean up the reactor building atmosphere upon containment isolation.

The SBGT System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Following a DBA, a minimum of one SBGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SBGT subsystem in the event of a single active failure.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SBGT System OPERABILITY is required during these MODES.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SBGT System in OPERABLE status is not required in MODE 4 or 5.

ACTIONS

A.1

With one SBGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status in 7 days. In this Condition, the remaining OPERABLE SBGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SBGT subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the SBGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

If both SBGT subsystems are inoperable in MODE 1, 2, or 3, the SBGT System may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 Immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SBGT subsystem ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure, can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system, however these components are not the most-limiting for overall system reliability at this SR Frequency.

SR 3.6.4.3.2

This SR verifies that the required SBGT filter testing is performed in accordance with Specification 5.5.7, Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow capability, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.2 (continued)

A Note has been added to this SR delaying the entry into associated Conditions and Required Actions for up to one hour. This is necessary because, due to a cross-tie duct between the two SBGT subsystems, the flow path through the SBGT subsystem not being tested must be isolated, making it inoperable, to establish conditions necessary to ensure the tested SBGT subsystem meets the filter train differential pressure requirements of the VFTP. During the testing, the ability to draw a vacuum on Secondary Containment is maintained by the subsystem under test. One hour minimizes the amount of time the SBGT subsystem is inoperable while providing enough time to perform the required testing. Additionally, LCO 3.0.5 provides allowances for post-maintenance testing required to return a SBGT subsystem to Operable status. The allowance provided by the Note avoids potential entry into LCO 3.0.3 (Condition D) during required routine surveillances and during demonstration of Operability for a previously inoperable subsystem under LCO 3.0.5.

SR 3.6.4.3.3

This SR verifies that each SBGT subsystem starts on receipt of an actual or simulated initiation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the Surveillance when performed at this Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR verifies that the filter cooler bypass damper can be opened and the fan started. This ensures that the ventilation mode of SBGT System operation is available. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This Surveillance can be performed with the reactor at power and operating experience has shown that these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 3.1.2.4.12.
2. UFSAR, Section 6.5.3.3.
3. UFSAR, Section 15.2.1

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, two 2400 gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Although the RHRSW pumps are rated at 2400 gpm, the DAEC has been evaluated to require only 2040 gpm per pump (Ref.4). Either of the two subsystems is capable of providing the required cooling capacity with two pumps operating to maintain safe shutdown conditions (Ref. 4). The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the UFSAR, Section 9.2.3.2, Reference 1.

Cooling water is pumped by the RHRSW pumps from the pump house through the tube side of the RHR heat exchangers, and discharges to either the Cooling Towers or the Cedar River.

The system is initiated manually from the control room. If operating during a Loss of Coolant Accident (LOCA), the system is automatically tripped to allow the diesel generators to automatically power only essential equipment needed to initially mitigate the accident (i.e., within the first 10 minutes). The system can be manually started any time the LOCA signal is manually overridden or clears and when sufficient load carrying capacity exists on the associated diesel generator when offsite power is not available. In any case, RHRSW System operation is not required anytime sooner than 10 minutes after a LOCA.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA and during limiting transients such as stuck open relief valves. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is discussed in the UFSAR, Section 6.2.1.3 and Chapter 15 (Refs. 2 and 3, respectively). These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The safety analyses for long term cooling were performed for various combinations of RHR System failures. The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. As discussed in the UFSAR, Section 15.2.1 (Ref. 4) for these analyses, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 10 minutes after a DBA. The RHRSW flow assumed in the analyses is 2040 gpm per pump with two pumps operating in one loop. In this case, the maximum suppression chamber water temperature and pressure are 215.3°F and 36.5 psig, respectively, which are below the maximum allowable temperature of 340°F and maximum allowable pressure of 62 psig.

The RHRSW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two RHRSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.

An RHRSW subsystem is considered OPERABLE when:

(continued)

BASES

LCO (continued)

a. Two pumps are OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the pump house and transferring the water to the RHR heat exchangers at the assumed flow rate.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head is bounded by the River Water Supply pump requirements (LCO 3.7.2, "River Water Supply (RWS) System and Ultimate Heat Sink (UHS)").

APPLICABILITY

In MODES 1, 2, and 3, the RHRSW System is required to be OPERABLE to support the OPERABILITY of the RHR System for primary containment cooling (LCO 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling,") and decay heat removal (LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System — Hot Shutdown"). The Applicability is therefore consistent with the requirements of these systems.

In MODES 4 and 5, the OPERABILITY requirements of the RHRSW System are determined by the systems it supports, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the RHR Shutdown Cooling System (LCO 3.4.8, “RHR Shutdown Cooling System-Cold Shutdown,” LCO 3.9.7, “RHR-High Water Level,” and LCO 3.9.8, “RHR-Low Water Level”), which require portions of the RHRSW System to be OPERABLE, will govern RHRSW System requirements during operation in MODES 4 and 5.

ACTIONS

A.1

With one RHRSW pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE RHRSW pumps are adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced RHRSW capability. The 30 day Completion Time is based on the remaining RHRSW heat removal capability and the low probability of a DBA with concurrent worst case single failure.

(continued)

BASES

ACTIONS (continued)

B.1

With one RHRSW pump inoperable in each subsystem, if no additional failures occur, then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA. However, an additional single failure in the RHRSW System could reduce the system capability below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time for restoring one inoperable RHRSW pump to OPERABLE status is based on engineering judgment, considering the level of redundancy provided.

C.1

Required Action C.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. With the unit in this condition, the remaining OPERABLE RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem could result in loss of RHRSW function. The Completion Time is based on the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring RHRSW during this period.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem.

This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS (continued)

D.1

With both RHRSW subsystems inoperable for reasons other than Condition B (e.g., both subsystems with inoperable flow paths, or one subsystem with an inoperable pump and one subsystem with an inoperable flow path), the RHRSW System is not capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time for restoring one RHRSW subsystem to OPERABLE status, is based on the Completion Times provided for the RHR suppression pool cooling function.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

E.1 and E.2

If the RHRSW subsystems cannot be restored to OPERABLE status within the associated Completion Times, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verifying the correct alignment for each power operated and automatic valve in each RHRSW subsystem flow path provides assurance that the proper flow paths will exist for RHRSW operation by ensuring valves are not inadvertently mispositioned. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be realigned to its accident position. This is acceptable because the RHRSW System is a manually initiated system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves. This SR is considered met for OPERABLE valves that are temporarily placed in a position other than the standby readiness position under appropriate administrative and procedural controls. The administrative and procedural controls (such as positioning during a Surveillance Test Procedure or operating in accordance with an approved Operating Instruction) ensure the Operators are cognizant of valve positions and ensure valves are promptly returned to the standby readiness position when the evolution is completed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

REFERENCES

1. UFSAR, Section 9.2.3.2.
2. UFSAR, Section 6.2.1.3.
3. UFSAR, Chapter 15.
4. UFSAR, Section 15.2.1.

B 3.7 PLANT SYSTEMS

B 3.7.2 River Water Supply (RWS) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The RWS System is designed to provide cooling water for the Emergency Service Water (ESW) and Residual Heat Removal Service Water (RHRSW) Systems, which provide required support for various systems required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RWS System also provides water to the Circulating Water System to make up for cooling tower evaporative losses, as required, during normal operation. Upon receipt of a Loss of Offsite Power or Loss of Coolant Accident (LOCA) signal, the radwaste dilution/cross-tie valves are closed, if open, the river water makeup valves fail open, and selected pumps are started to ensure adequate delivery of water to the RHRSW/ESW Stilling Basin in the pump house. A two minute delay is implemented if a running RWS pump trips due to a dead supply bus and is subsequently restarted in response to a Loss of Offsite Power or LOCA signal.

The RWS System consists of the UHS and two independent and redundant subsystems. Each of the two RWS subsystems is made up of a header, two 6000 gpm pumps, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to support the required systems with one pump operating. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other system.

Cooling water is pumped from the Cedar River by the RWS pumps to the RHRSW/ESW Stilling Basin in the pump house through the two main headers. From there, the water is either used by the RHRSW and/or ESW Systems, or is supplied to the Circulating Water System to replace evaporation losses from the cooling towers during normal plant operation. Since a common Stilling Basin is fed from either RWS subsystem and is connected to both RHRSW/ESW pump pits, either RWS subsystem can feed both RHRSW/ESW subsystems. The adequacy of the Cedar River as the UHS is discussed in Reference 4. The minimum river level requirement ensures that sufficient suction pressure will be present to allow the RWS

(continued)

BASES

BACKGROUND (continued)

pumps to deliver sufficient flow to the pump house stilling basin. The minimum river depth requirement ensures that the minimum required flow rate, 13 cubic feet per second (cfs), will be available to the RWS pump pits. The maximum river water temperature ensures that the water available for cooling safety related heat loads can remove heat in the quantities assumed in any safety analyses.

APPLICABLE SAFETY ANALYSES

Sufficient water inventory is available for the RWS System if the Ultimate Heat Sink specification is met. The ability of the RWS System to supply sufficient water to support the RHRSW and ESW Systems in providing long term cooling of the reactor containment, as assumed in evaluations of the equipment required for safe reactor shutdown, is presented in the UFSAR (Ref 3). These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The ability of the RWS System to supply sufficient makeup water in support of systems that provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 1 and 2. The ability to provide onsite emergency AC power is dependent on the ability of the RWS System to supply sufficient makeup water for use by the ESW System in cooling the DGs.

The RWS System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RWS subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of RWS is required to provide makeup water to support the ESW and RHRSW Systems in providing the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of RWS must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has an OPERABLE UHS, one OPERABLE pump, and an OPERABLE flow path capable of taking suction from the intake structure and transferring the water to the RHRSW/ESW Stilling Basin in the pump house.

(continued)

BASES

LCO (continued)

The OPERABILITY of the UHS is based on having a minimum river water level of 725.2 ft mean sea level, a minimum river depth of 12 inches and a maximum river water temperature of 95°F. The minimum river level is based on the minimum level assumed in the RWS System resistance calculations. The minimum river depth is based on the minimum required flow rate into the Intake Structure of 13 cfs to meet emergency cooling requirements. The maximum river temperature is based on the heat removal calculations for components supported by the RHRSW and ESW Systems.

APPLICABILITY

In MODES 1, 2, and 3, the RWS System and UHS are required to be OPERABLE to support OPERABILITY of the RHRSW and ESW Systems.

In MODES 4 and 5, the OPERABILITY requirements of the RWS System and UHS are determined by the systems they support, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, LCOs of the systems supported by the RWS System and UHS will govern RWS System and UHS OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

With one RWS subsystem inoperable, the RWS subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE RWS subsystem is adequate to supply sufficient makeup water. However, the overall reliability is reduced because a single failure in the OPERABLE RWS subsystem could result in loss of RWS function.

The 7 day Completion Time is based on the redundant RWS System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable RHRSW or ESW subsystem.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the RWS subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both RWS subsystems are inoperable, or the UHS is determined to be inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions of Condition B are modified by a Note indicating that the Applicable Condition of LCO 3.4.7 "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," be entered and Required Actions taken if the inoperable RWS subsystem results in an inoperable RHR Shutdown Cooling subsystem. The Note also alerts the operator that RHR shutdown cooling will be inoperable when the Applicability of LCO 3.4.7 is met. This allows the operator to make provisions for an alternate method of decay heat removal for each inoperable RHR shutdown cooling subsystem, in accordance with the Required Actions of LCO 3.4.7. This is in accordance with LCO 3.0.6 and ensures proper actions are taken for these components.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies the river water level to be sufficient for the proper operation of the RWS pumps (net positive suction head and pump vortexing are considered in determining this limit). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.2

Verification of the River Water temperature ensures that the heat removal capability of the RHRSW and ESW Systems are within the assumptions of the DBA analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.3

This SR verifies the river depth to provide sufficient flow to meet the plant's emergency cooling requirements. River depth is measured in front of the Intake Structure. This SR is modified by a note which allows this SR not to be performed when river depth is ≥ 2 feet. If river depth falls below 2 feet, this SR is performed periodically until the river depth increases to at least 2 feet. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency will ensure that river bed conditions are monitored until corrective actions, such as dredging, are implemented.

SR 3.7.2.4

Verifying the correct alignment for each power operated and automatic valve in each RWS subsystem flow path provides assurance that the proper flow paths will exist for RWS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.2.5

This SR verifies the river depth to provide sufficient flow to meet the plant's emergency cooling requirements. River depth is measured in front of the Intake Structure. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience related to trending of river bottom fluctuations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.6

This SR verifies that the automatic isolation valves of the RWS System will automatically switch to the safety or emergency position to provide cooling water exclusively to the RHRSW/ESW Stilling Basin in the pump house during an accident event. This is demonstrated by the use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of one of the two RWS pumps in each subsystem.

The Surveillance frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Chapter 15.
2. UFSAR, Section 6.2.2.
3. UFSAR, Section 9.2.2.
4. UFSAR, Section 1.8.27.

B 3.7 PLANT SYSTEMS

B 3.7.3 Emergency Service Water (ESW) System

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the Diesel Generators (DGs), room coolers for Emergency Core Cooling System equipment, Control Building Chillers, and various minor heat loads required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The ESW System also provides cooling to unit components, as desired during normal operation. Upon receipt of a start signal from its associated DG, each ESW pump is automatically started, i.e., the ESW start circuitry is dependent upon the DG control system.

The ESW System consists of two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, one 1200 gpm pump, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to support the required systems. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other subsystem. The capability exits to manually cross connect the ESW subsystems using a removable spool piece, however, one ESW pump cannot be used to supply both ESW loops.

Cooling water is pumped from the RHRSW/ESW pump pit in the pump house by the ESW pumps to the essential components through the two main headers. After removing heat from the components, the water is either discharged from the DG directly to a storm sewer, or is combined with water discharged from the RHRSW System and Well Water System and discharged to the Circulating Water System to replace evaporation losses from the cooling towers, or directly to the river via the dilution structure or deicing. A complete description of the ESW System is presented in the UFSAR, Section 9.2.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the ESW System to support long term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the UFSAR, Chapter 15 (Ref. 2). These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in Reference 2. The ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the DGs. The long term cooling capability of the RHR, core spray, and RHR service water pumps is also dependent on the cooling provided by the ESW System, via either motor cooling or room cooling. In addition, during shutdown cooling mode with reactor coolant temperatures > 212°F, the RHR pumps are dependent upon the ability of the ESW System to provide pump seal cooling.

The ESW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of ESW is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two subsystems of ESW must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has one OPERABLE pump and an OPERABLE flow path capable of taking suction from the RHRSW/ESW pump pit in the pump house and transferring the water to the appropriate equipment.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the ESW pumps is ensured to be present by the RWS requirements (LCO 3.7.2, "River Water Supply and Ultimate Heat Sink (UHS)").

Because the ESW automatic start circuit is dependent upon the DG control system, there are some DG activities that inhibit the DG from starting up, such as tripping the fuel racks or placing the Control Room handswitch in pull-to-lock, that also block the ESW automatic start signal. These activities can prevent ESW from automatically supplying cooling water to other key components during an event that is not dependent upon the EDG being OPERABLE (i.e. offsite AC power is available) and thus, impact ESW OPERABILITY.

(continued)

BASES

LCO (continued)

The isolation of the ESW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ESW System.

APPLICABILITY

In MODES 1, 2, and 3, the ESW System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the ESW System. Therefore, the ESW System is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the ESW System is determined by the systems if supports, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the systems supported by the ESW System will govern OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

With one ESW subsystem inoperable, the ESW subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE ESW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ESW subsystem could result in loss of ESW function.

The 7 day Completion Time is based on the redundant ESW System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG.

Required Action A.1 is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources-Operating," LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," be entered and Required Actions taken if the inoperable ESW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the ESW subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both ESW subsystems are inoperable the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least Mode 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

Verifying the correct alignment for each power operated, and automatic valve in each ESW subsystem flow path provides assurance that the proper flow paths will exist for ESW operation by ensuring valves are not inadvertently mispositioned. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves. This SR is considered met for OPERABLE valves that are temporarily placed in a position other than the standby readiness position under appropriate administrative and procedural controls. The administrative and procedural controls (such as positioning during a Surveillance Test Procedure or operating in accordance with an approved Operating Instruction) ensure the Operators are cognizant of valve positions and ensure valves are promptly returned to the standby readiness position when the evolution is completed.

This SR is modified by a Note indicating that isolation of the ESW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ESW System. As such, when all ESW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the ESW System is still OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.3.2

This SR verifies the automatic start capability of the ESW pump in each subsystem. This is demonstrated by the use of an actual or simulated initiation signal

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.2.3.
2. UFSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.4 Standby Filter Unit (SFU) System

BASES

BACKGROUND

The SFU System provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals or smoke.

The safety related function of the SFU System includes two independent and redundant high efficiency air filtration subsystems for emergency treatment of outside supply air and a Control Building Envelope (CBE) boundary that limits the inleakage of unfiltered air. Each SFU subsystem consists of a demister, an electric heater, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork, valves or dampers, doors, barriers, and instrumentation. Demisters remove water droplets from the airstream. HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The CBE is the area within the confines of the CBE boundary that contains the spaces that control building occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control building, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CBE is protected during normal operation, natural events, and accident conditions. The CBE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CBE. The OPERABILITY of the CBE boundary must be maintained to ensure that the inleakage of unfiltered air into the CBE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CBE occupants. The CBE and its boundary are defined in the Control Building Envelope Habitability Program.

The SFU System is a standby system, parts of which also operate during normal unit operations to maintain the CBE. Upon receipt of the initiation signal (indicative of conditions that could result in radiation exposure to CBE occupants), the SFU System automatically starts and a system of dampers isolates the CBE to minimize infiltration of contaminated air into the CBE. Outside air is taken in at the normal ventilation intake and is passed through

(continued)

BASES

BACKGROUND (continued)

one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles before being mixed with the recirculated air. The air (outside and/or recirculated) is cooled by Air Conditioning (AC) units supplied by the Control Building Chillers (CBCs). The SFUs and AC units share common ductwork such that either SFU may supply outside air to either AC unit. However, the CBCs and AC units are addressed as part of LCO 3.7.5, "Control Building Chiller System."

The SFU System is designed to maintain a habitable environment in the CBE for a 30 day continuous occupancy after a DBA without exceeding 5 rem total effective dose equivalent (TEDE). A single SFU subsystem operating at a flow rate of 1000 cfm ±10% will pressurize the control room to $\geq$ 0.1 inches water gauge pressure above atmospheric pressure, under calm wind conditions (i.e. less than 5 mph wind speed) relative to the Reactor Building and outside atmosphere. A single SFU subsystem operating at a flow rate of 1000 cfm ±10% will also pressurize the CBE to a positive pressure above atmospheric pressure, under calm wind conditions (i.e. less than 5 mph wind speed) relative to external areas adjacent to the CBE boundary. This will minimize infiltration of air from all surrounding areas adjacent to the CBE boundary.

Other areas in the CBE that directly communicate with the CBE via HVAC system ductwork or doors are also required to maintain a positive pressure relative to the adjacent areas outside the CBE. This will assure that leakage is from the CBE to the adjacent areas or outdoors. SFU System operation in maintaining a habitable environment in the CBE is discussed in the UFSAR, Sections 6.4 and 9.4.4, (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the SFU System to maintain the habitability of the CBE is an explicit assumption for the safety analyses presented in the UFSAR, Sections 6.4 and 15.2 (Refs. 1 and 3, respectively). The SFU System is assumed to operate in the isolation mode following a DBA. The radiological doses to the CBE occupants as a result of the various DBAs are summarized in Reference 3. No single active failure will cause the loss of CBE habitability.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

There are no offsite or onsite hazardous chemicals that would pose a credible threat to CBE habitability (Ref. 7). Consequently, engineered controls for the CBE are not required to ensure habitability against a chemical threat.

The evaluation of a smoke challenge demonstrated that smoke will not result in the inability of the CBE occupants to control the reactor either from the control room or from the remote shutdown system (Ref. 7). The assessment verified that a fire or smoke event anywhere within the plant would not simultaneously render the remote shutdown system and the CBE uninhabitable, nor would it prevent access from the CBE to the remote shutdown system in the event remote shutdown is required. No automatic SFU actuation is required for hazardous chemical releases or smoke and no Surveillance Requirements are required to verify OPERABILITY in cases of hazardous chemicals or smoke.

The SFU System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two redundant subsystems of the SFU System are required to be OPERABLE to ensure that at least one is available, if a single active failure disables the other subsystem. Total SFU System failure, such as from a loss of both ventilation subsystems or from an inoperable CBE boundary, could result in exceeding a dose of 5 rem TEDE to the CBE occupants in the event of a DBA.

Each SFU subsystem is considered OPERABLE when the individual components necessary to limit CBE occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorbers are not excessively restricting flow and are capable of performing their filtration functions; and

c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

(continued)

BASES

LCO (continued)

In order for the SFU subsystems to be considered OPERABLE, the CBE boundary must be maintained such that the CBE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs. In the event of an inoperable CBE boundary in MODES 1, 2, or 3, mitigating actions are required to ensure CBE occupants are protected from hazardous chemicals and smoke.

DAEC does not have automatic SFU actuation for hazardous chemicals or smoke. Current practices at DAEC do not utilize chemicals in sufficient quantity to present a chemical hazard to the CBE. Smoke is not considered in the DAEC safety analysis. Therefore, there are no specific limits at DAEC for hazardous chemicals or smoke.

The LCO is modified by a Note allowing the CBE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CBE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through the doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CBE. This individual will have a method to rapidly close the opening and to restore the CBE boundary to a condition equivalent to the design condition when a need for CBE isolation is indicated.

APPLICABILITY

In MODES 1, 2, and 3, the SFU System must be OPERABLE to ensure that the CBE will remain habitable during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced because of the pressure and temperature limitations in these MODES. Therefore, maintaining the SFU System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

(continued)

BASES

APPLICABILITY (continued)

a. During CORE ALTERATIONS; and

b. During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

With one SFU subsystem inoperable, for reasons other than an inoperable CBE boundary, the inoperable SFU subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE SFU subsystem is adequate to perform the CBE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE subsystem could result in loss of the SFU System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

B.1, B.2, and B.3

If the unfiltered inleakage of potentially contaminated air past the CBE boundary and into the CBE can result in CBE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), the CBE boundary is inoperable. As discussed in the Applicable Safety Analyses section, the DAEC licensing basis identifies that CBE inleakage limits for hazardous chemicals and smoke are not necessary to protect the CBE occupants. Allowing verification by administrative means for hazardous chemicals and smoke is considered acceptable, since the limit established for radiological events is the limiting value for determining entry into Condition B for an inoperable CBE boundary. These administrative controls consist of the following:

- Verification that the periodic check of onsite and offsite hazardous chemical sources has been performed within the last year; and

- Verification that the smoke analysis of Reference 7 remains valid and current.

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

A periodic check of onsite and offsite hazardous chemical sources takes place once per year to ensure no onsite or offsite sources of hazardous chemicals exist that could present a chemical hazard to CBE ocupants. No onsite or offsite sources of hazardous chemicals currently exist that could present a chemical hazard to CBE occupants.

Actions must be taken to restore an OPERABLE CBE boundary within 90 days.

During the period that the CBE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CBE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CBE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CBE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional.

The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CBE occupants within analyzed limits while limiting the probability that CBE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CBE boundary.

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable SFU subsystem or the CBE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1, D.2.1, and D.2.2

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment or during CORE ALTERATIONS, if the inoperable SFU subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE SFU subsystem may be placed in the isolation mode (i.e., one SFU subsystem in operation with the control building isolated). This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected. An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the CBE. This places the unit in a condition that minimizes the accident risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

E.1

If both SFU subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CBE boundary (i.e., Condition B), the SFU System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition F are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment or during CORE ALTERATIONS, with two SFU subsystems inoperable, or with one or more SFU subsystems inoperable due to an inoperable CBE boundary, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the CBE. This places the unit in a condition that minimizes the accident risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

Operating each SFU subsystem for $\geq$ 15 minutes ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure, can be detected for corrective action. Since the SFU charcoal is tested at a Relative Humidity $\geq$ 95%, extended operation of the electric heaters is not required. Thus, each subsystem need only be operated for $\geq$ 15 minutes to demonstrate the function of each subsystem. The function of the SFU electric heaters is to pre-heat incoming air to above 40°F to ensure adsorption occurs within the temperature range that charcoal testing is performed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.2

This SR verifies that the required SFU testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.4.3

This SR verifies that on an actual or simulated initiation signal, each SFU subsystem starts and operates. This SR also ensures that the control building isolates. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Standby Filter Unit Instrumentation," overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.7.4.4

This SR verifies the OPERABILITY of the CBE boundary by testing for unfiltered air inleakage past the CBE boundary and into the CBE. The details of the testing are specified in the Control Building Envelope Habitability Program.

The CBE is considered habitable when the radiological dose to CBE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CBE occupants are protected from hazardous chemicals and smoke. For DAEC, there is no automatic SFU actuation for hazardous chemical releases or smoke and there are no Surveillance Requirements that verify OPERABILITY in cases of hazardous chemicals or smoke. This SR verifies that the unfiltered air inleakage into the CBE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CBE boundary to OPERABLE status provided mitigating actions can ensure that the CBE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.4 (continued)

Guide 1.196, Section C.2.7.3, (Ref. 4) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 5). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 6). Options for restoring the CBE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CBE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CBE boundary has been restored to OPERABLE status.

REFERENCES

1. UFSAR, Section 6.4.
2. UFSAR, Section 9.4.4.
3. UFSAR, Section 15.2.
4. Regulatory Guide 1.196.
5. NEI 99-03, "Control Room Habitability Assessment," June 2001.
6. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).
7. Letter from Mark A. Peifer (NMC, LLC) to Document Control Desk (USNRC) dated January 28, 2005, “Generic Letter 2003-01: Control Room Habitability – Design Bases, Licensing Bases and Inleakage Testing Results.” (ADAMS Accession No. ML050390308).

B 3.7 PLANT SYSTEMS

B 3.7.5 Control Building Chiller (CBC) System

BASES

BACKGROUND

The CBC System provides temperature control for the control building HVAC system under both normal and accident conditions.

The CBC System consists of two independent, redundant subsystems that provide cooling of recirculated control room air. Each subsystem consists of cooling coils, fans, a chiller, a compressor, ductwork, dampers, and instrumentation and controls to provide for control room temperature control. The CBCs receive water from both the ESW System and the Well Water System. Only the ESW System is required by this LCO.

The CBC System is designed to provide a controlled environment under both normal and accident conditions. Because the source of control room air is common with the air distributed to the remainder of the control building, no special means of isolating just the control room is provided. A single subsystem provides the required temperature control to maintain a suitable control building environment. The design conditions for the control room environment are 75°F dry bulb and 50% relative humidity. The CBC System operation in maintaining the control room temperature is discussed in the UFSAR, Section 9.4.4.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CBC System is to maintain the control room temperature for a 30 day continuous occupancy.

The CBC System components are arranged in redundant safety related subsystems. During emergency operation, the CBC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single failure of a component of the CBC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The CBC System is designed in accordance with Seismic Category I requirements. The CBC System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

The CBC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Two independent and redundant subsystems of the CBC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The CBC System is considered OPERABLE when the individual components necessary to maintain the control building temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls. A CBC is considered inoperable if it trips and cannot be promptly restarted. Therefore, a CBC that spuriously trips and can subsequently be restarted in a reasonable period of time, is not considered inoperable. In addition, during conditions in MODES other than MODES 1, 2, and 3 when the CBC System is required to be OPERABLE (e.g., during CORE ALTERATIONS), the necessary portions of the ESW System, RWS System, and the Ultimate Heat Sink are also required as part of the OPERABILITY requirements covered by this LCO.

APPLICABILITY

In MODE 1, 2, or 3, the CBC System must be OPERABLE to ensure that the control building temperature will not exceed equipment OPERABILITY limits.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident (DBA) are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CBC System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During CORE ALTERATIONS; and

b. During movement of irradiated fuel assemblies in the secondary containment.

(continued)

BASES (continued)

ACTIONS

A.1

With one CBC subsystem inoperable, the inoperable CBC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE CBC subsystem is adequate to perform the control building air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control building air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control building isolation, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

If both CBC subsystems are inoperable, the CBC System may not be capable of performing its intended function. Therefore, the control building area temperatures are required to be monitored to ensure that temperatures are being maintained low enough that equipment in the control building is not adversely affected. To ensure temperatures in the control building are maintained low enough, temperatures are required to be monitored in the control room as well as both essential switchgear rooms. Although design conditions for the control room environment are 75ºF dry bulb and 50% relative humidity, maintaining control room area temperatures less than 90ºF during the 72 hour Completion Time assures that safety-related equipment will remain less than the maximum operating temperature of 104ºF. With the control building temperatures being maintained within the temperature limit, 72 hours is allowed to restore a CBC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control building area temperatures are being maintained within limits and the low probability of an event occurring requiring control building isolation.

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable CBC subsystem(s) cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS (continued)

D.1, D.2.1 and D.2.2

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment or during CORE ALTERATIONS, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CBC subsystem may be placed immediately in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

E.1 and E.2

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

During movement of irradiated fuel assemblies in the secondary containment or during CORE ALTERATIONS, if Required Actions B.1 and B.2 cannot be met within the required Completion Times, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control building. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies that the heat removal capability of the system is sufficient to remove available control building heat load. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is appropriate since significant degradation of the CBC System is not expected over this time period.

REFERENCES

1. UFSAR, Section 9.4.4.2.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND

During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the Steam Jet Air Ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases.

The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the 30 minute holdup line.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Steam-Line Break Accident (Roof Top Release) (Ref. 3). This analysis assumes the concentrations of radionuclides in the reactor water are those associated with an assumed stack gas release limit of 1,000,000 µCi/sec (1.0 Ci/sec).

The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Restricting the gross radioactivity rate of noble gases from the main condenser (Ref. 1) provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 50.67 (Ref. 2) in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50. The offgas pretreatment radiation monitor indicates in mr/hr, and is set to initiate an alarm if the monitor exceeds a trip setting equivalent to 1.0 Ci/second of noble gases after 30 minutes delay in the offgas holdup lines.

(continued)

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment, the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a main steam line rupture.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR requires a periodic isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by $\geq$ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable, based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. UFSAR, Section 11.3.3.

2. 10 CFR 50.67.

3. UFSAR, Section 15.2.1.5.

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is slightly less than 21% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of two valves connected to the main steam lines at the bypass valve chest, which is between the main steam isolation valves and the turbine stop valve chest. Each of these two valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro-Hydraulic Control System, as discussed in the UFSAR, Sections 7.7.2.3.1, 10.2.2 and 10.4.4 (Refs. 1, 3 and 4, respectively). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser. However, because turbine first stage pressure is used to enable the RPS and EOC-RPT trips on TSV and TCV closure, bypass valve opening can impact the OPERABILITY of those trips.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the Feedwater Controller Failure - Maximum Demand transient, as discussed in the UFSAR, Section 15.1.1.1 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in a MCPR penalty. The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during certain events that cause rapid pressurization, so that the Safety Limit MCPR is not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow this LCO to be met. The MCPR limits for the inoperable Main Turbine Bypass System are specified in the COLR. An OPERABLE Main Turbine Bypass valve requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at $\geq$ 21.7% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during the Feedwater Controller Failure - Maximum Demand transient. As discussed in the Bases for LCO 3.2.2, sufficient margin to these limits exists at $<$ 21.7% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1 and A.2

If the Main Turbine Bypass System is inoperable (one or both bypass valves inoperable), and the MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

(continued)

BASES

ACTIONS (continued)

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status and the MCPR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 21.7% RTP. As discussed in the Applicability section, operation at < 21.7% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the Feedwater Controller Failure Maximum Demand transient. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on operating experience, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint. In addition, because this SR makes the RPS and EOC-RPT trips on TSV and TCV closure inoperable when performed above 26% RTP (Ref. SRs 3.3.1.1.16 and 3.3.4.1.4), the Frequency also considers the impact on those functions as well.

SR 3.7.7.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant startup and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. In addition, as noted above, cycling the valves also impacts the RPS and EOC-RPT trips on TSV and TCV closure. Thus, it is preferable to perform this Surveillance when those trips are not required to be OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.2 (continued)

Operating experience has shown this Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in the UFSAR (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. In addition, as noted above, cycling the valves also impacts the RPS and EOC-RPT trips on TSV and TCV closure. Thus, it is preferable to perform this Surveillance when those trips are not required to be OPERABLE. Operating experience has shown this Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 7.7.2.3.1.
2. UFSAR, Section 15.1.1.1.
3. UFSAR, Section 10.2.2.
4. UFSAR, Section 10.4.4.

B 3.7 PLANT SYSTEMS

B 3.7.8 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident.

A general description of the spent fuel storage pool design is found in the UFSAR, Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in the UFSAR, Section 15.2.5 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are well below the guideline limits of 10 CFR 50.67 (Ref. 3) and meet the exposure guidelines of Regulatory Guide 1.183 (Ref. 4). A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in UFSAR, Section 15.2.5 (Ref. 2).

The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core. The consequences of a fuel handling accident over the spent fuel storage pool are no more severe than those of the fuel handling accident over the reactor core, as discussed in the UFSAR, Section 15.2.5 (Ref. 2). The water level in the spent fuel storage pool provides for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident.

The spent fuel storage pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel storage pool since the potential for a release of fission products exists.

ACTIONS

A.1

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

When the initial conditions for an accident cannot be met, action must be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the movement of irradiated fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable, and all water level changes are controlled by unit procedures.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 9.1.2.
2. UFSAR, Section 15.2.5.
3. 10 CFR 50.67.
4. Regulatory Guide 1.183.

B 3.7 PLANT SYSTEMS

B 3.7.9 Control Building/Standby Gas Treatment (CB/SBGT) Instrument Air System

BASES

BACKGROUND The CB/SBGT Instrument Air System (Ref. 1) is designed to provide
compressed air to support:

- closure of the reactor building-to-suppression chamber vacuum breaker butterfly valves
- leak tightness of the reactor building-to-suppression chamber vacuum breaker butterfly valves (by pressurizing the T-ring seals) when closed
- leak tightness of the primary containment purge system isolation valves (by pressurizing the T-ring seals) when closed
- closure of the drywell cooling water containment isolation valves
- SBGT flow control and filter cooler bypass damper opening
- Standby Filter Unit (SFU) flow control
- ventilation flow path and temperature control for the Control Building Chiller (CBC) System, which is also the ventilation flow path for the SFU System

These systems and components function to limit fission product release and control the environment from the which the unit can be safely operated following a Design Basis Accident (DBA) (Refs. 2, 3, 4, 5 and 6).

The CB/SBGT Instrument Air System consists of two independent and redundant subsystems. Each of the two CB/SBGT Instrument Air subsystems is made up of a compressor, air receiver, associated instrumentation, and piping. The air receivers are normally supplied by the plant instrument air system. If the pressure in the air receiver decreases below 78 psig (nominal), then the CB/SBGT

(continued)

BASES

BACKGROUND (continued)

Instrument Air compressor will automatically start. With the air receiver pressure higher than the plant instrument air system, check valves will close to provide isolation of each CB/SBGT Instrument Air subsystem.

Either of the two subsystems is capable of providing compressed air to support the required systems. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other subsystem.

APPLICABLE SAFETY ANALYSES

The ability of the CB/SBGT Instrument Air System to provide compressed air is an implicit assumption in evaluations of the equipment required to limit fission product release and control the environment from which the unit can be safely operated following a DBA.

The CB/SBGT Instrument Air System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The CB/SBGT Instrument Air subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of CB/SBGT Instrument Air is required to support operation of SBGT, SFU, CBC, and containment isolation assumed in the safety analyses. To ensure this requirement is met, two subsystems of CB/SBGT Instrument Air must be OPERABLE. At least one subsystem will operate if the worst single active failure occurs coincident with the loss of offsite power.

The isolation of the CB/SBGT Instrument Air System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the CB/SBGT Instrument Air System.

APPLICABILITY

In MODES 1,2,and 3, the CB/SBGT Instrument Air System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the CB/SBGT Instrument Air System. Therefore, the CB/SBGT Instrument Air System is required to be OPERABLE in these MODES.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the OPERABILITY requirements of the CB/SBGT Instrument Air System are determined by the systems it supports, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the systems supported by the CB/SBGT Instrument Air System will govern OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

Required Action A.1 is intended to provide assurance that a loss of the plant instrument air system, during the period that a CB/SBGT Instrument Air subsystem is inoperable, does not result in a complete loss of safety function of critical systems.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilites. This Completion Time also allows for an exception to the normal “time zero” for beginning the allowable out of service time “clock.” In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable CB/SBGT Instrument Air subsystem exists; and

b. A required feature on the other division is inoperable.

If, at any time during the existence of this Condition (one CB/SBGT Instrument Air subsystem inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required CB/SBGT Instrument Air subsystem inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE CB/SBGT Instrument Air subsystem results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown. Additionally, the 4 hour Completion Time takes in to account the capability of the OPERABLE CB/SBGT Instrument Air subsystem, reasonable time for repairs, and low probability of a DBA during this period.

(continued)

BASES

ACTIONS (continued)

A.2

With one CB/SBGT Instrument Air subsystem inoperable, the CB/SBGT Instrument Air subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE CB/SBGT Instrument Air subsystem is adequate to support the SBGT, SFU, CBC, and containment isolation functions. However, the overall reliability is reduced because a single failure in the OPERABLE CB/SBGT Instrument Air subsystem could result in a loss of the supported functions.

The 7 day Completion Time is based on the redundant CB/SBGT Instrument Air System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occuring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG or ESW subsystem.

B.1 and B.2

If the CB/SBGT Instrument Air subsystem cannot be restored to OPERABLE status within the associated Completion Time or both CB/SBGT Instrument Air subsystems are inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES (continued)

SUREVEILLANCE REQUIREMENTS

SR 3.7.9.1

Operating each CB/SBGT Instrument Air compressor for ≥ 20 minutes allows the oil and other components to reach their operating temperature. This periodic operation removes condensation which may cause rusting in the cylinders, if it were to accumulate. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency and the operating time are based on vendor recommendations.

SR 3.7.9.2

This SR verifies that each CB/SBGT Instrument Air subsystem has the capability to deliver suffcient quantity of compressed air to support the SBGT, SFU, CBC, and containment isolation functions. This SR takes into account both the compressor capacity and the integrity of the distribution system.

This SR also verifies the automatic start capability of the CB/SBGT Instrument Air compressor in each subsystem. This is demonstrated by the use of an actual or simulated initiation signal.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is consistent with the Frequency for pump testing in accordance with the INSERVICE TESTING PROGRAM requirements. Therefore, this Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.3.1.2.1.
2. UFSAR, Section 6.2.4.
3. UFSAR, Section 6.2.5.
4. UFSAR, Section 6.5.3.3.
5. UFSAR, Section 6.4.2.
6. UFSAR, Section 9.4.4.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources — Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred and alternate preferred), and the onsite standby power sources (Diesel Generators (DGs) 1G-31 and 1G-21). As discussed in UFSAR Section 3.1.2.2.8 (Ref. 1), the design of the AC Electrical Power System provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) Systems via essential buses 1A3 and 1A4.

The Class 1E AC Distribution System is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two preferred offsite power supplies and a single DG.

Offsite power is supplied to the 161 kV and 345 kV switchyards from the transmission network by six transmission lines. The 345 kV switchyard and the 161 kV switchyard are connected via the autotransformer, and both sections of the switchyard are connected to the transmission grid by at least two independent lines. From the 161 kV switchyard preferred power source breakers CB5550 and/or CB5560, a single overhead transmission line feeds the startup transformer. From the startup transformer, dual isolated secondary windings provide feeds to the 4160 volt essential buses, 1A3 and 1A4, through separate bus supply lines and circuit breakers. The startup transformer is sized to supply all plant power (both essential and non-essential loads) during unit startup. From the 161 kV switchyard alternate preferred power source breaker CB8490, a single 34.5 kV underground line feeds the standby transformer. From the standby transformer, a single 4160 volt line feeds both essential buses through separate bus supply circuit breakers. A detailed description of the offsite power network and circuits to the onsite Class 1E essential buses is found in the UFSAR, Sections 8.2.1.3 and 8.3.1.1.5 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls

(continued)

BASES

BACKGROUND (continued)

required to transmit power from the offsite transmission network to the onsite Class 1E essential bus or buses. Startup transformer (1X3) provides the normal source of power to the essential buses 1A3 and 1A4. If either 4.16 kV essential bus loses power, an automatic transfer from the startup transformer to the standby transformer (1X4) occurs.

The startup transformer and standby transformer are both sized to accommodate the starting of all ESF loads on receipt of an accident signal. Emergency loads are sequenced onto the essential buses regardless of the source of power (onsite or offsite).

The onsite standby power source for 4.16 kV essential buses 1A3 and 1A4 consists of two DGs. DGs 1G-31 and 1G-21 are dedicated to essential buses 1A3 and 1A4, respectively. A DG starts automatically on a Loss of Coolant Accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an essential bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of essential bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the essential bus on a LOCA signal alone. Following the trip of offsite power, non emergency loads powered from essential buses are load shed. When the DG is tied to the essential bus, loads are then sequentially connected to its respective essential bus. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG.

In the event of a loss of both the preferred power source and the alternate preferred power source, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the DGs in the process. Within 25 seconds after the initiating signal is received, all automatic and permanently

(continued)

BASES

BACKGROUND (continued)

connected loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for the DGs satisfy the intent of Safety Guide 9 as discussed in UFSAR Section 1.8.9 (Ref. 3). DGs 1G-31 and 1G-21 have the following ratings:

a. 2850 kW continuous,

b. 3000 kW 2000 hours, and

c. 3250 kW 300 hours.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 15 (Ref. 5), assume ESF Systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System and two separate and independent DGs

(continued)

BASES

LCO (continued)

(1G-31 and 1G-21) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an Abnormal Operational Transient or a postulated DBA. Qualified offsite circuits are those that are described in the UFSAR, and are part of the licensing basis for the unit.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the essential buses. In accordance with commitments made in response to Generic Letter 2006-02 (Ref. 4), Condition C is entered whenever the grid operator (e.g., Midwest Independent System Operator (MISO)) determines that offsite power grid conditions are such that a trip of the DAEC turbine/generator would lead directly to voltages in the DAEC switchyard below the trip setpoints for Loss of Power (LOP) Instrumentation (LCO 3.3.8.1). The two offsite circuits consist of: 1) either the incoming circuit breaker (1400) and disconnects (1401 and 1402) or incoming circuit breaker (2690) and disconnects (2691 and 2692), the overhead 161 kV buswork, circuit breaker (1590) and disconnect (1591), the Reserve Auxiliary Transformer (1X5), circuit breaker (8490) and disconnect (8491), the underground 34.5 kV line, the standby transformer (1X4), the 4160 volt supply line and the two supply circuit breakers (1A301 and 1A401) to essential buses 1A3 and 1A4, respectively, and 2) either the incoming circuit breaker (5550) and disconnects (5551 and 5552) or incoming circuit breaker (5560) and disconnects (5553 and 5555), the overhead 161 kV line, the startup transformer (1X3), the two 4160 volt supply lines and the two supply circuit breakers (1A302 and 1A402) to essential buses 1A3 and 1A4, respectively.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective essential bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the essential buses. Proper sequencing of loads, including non-essential load shedding capability, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than

(continued)

BASES

LCO (continued)

one essential bus, with slow transfer capability to the other circuit OPERABLE, and not violate separation criteria.

A circuit that is not connected to either essential bus is required to have OPERABLE slow transfer interlock mechanisms to both essential buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of Abnormal Operational Transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 4 and 5 and other Conditions in which AC sources are required are covered in LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the

(continued)

BASES

ACTIONS

A.1 (continued)

second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

The power sources for the plant auxiliary power system are sufficient in number and have adequate electrical and physical independence to ensure that no single probable event could interrupt all auxiliary power at one time. In the condition of one inoperable offsite power source, all essential and non-essential buses remain OPERABLE and the remaining offsite power source continues to provide a highly reliable power source. Required Action A.2 requires restoring the inoperable offsite circuit to OPERABLE status, prior to entering MODE 2 from MODE 3 or 4. The inoperable offsite circuit must be restored to OPERABLE status prior to entering MODE 2 from MODE 3 or 4 to ensure that at least two offsite power sources will be available before the reactor is taken beyond just critical.

Entry into MODE 1 from MODE 2 with an inoperable offsite circuit is acceptable since LCO 3.0.4 allows continued operation of the unit in a MODE or other specified condition in which operation for an unlimited period of time is allowed. The inoperable offsite circuit only has to be repaired prior to entering MODE 2 from MODE 3 or 4.

B.1

To ensure a highly reliable power source remains with one DG inoperable, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

(continued)

BASES

ACTIONS (continued)

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Failures of "redundant required features" refers to inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division (Division 1 or 2) is inoperable.

If, at any time during the existence of this Condition (one DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

(continued)

BASES

ACTIONS

B.2 (continued)

The remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3

Required Action B.3 requires that the cause of the inoperability be evaluated to ensure a common cause failure does not exist that could render the OPERABLE DG inoperable. This evaluation may be performed by analysis or inspection or by demonstration of OPERABILITY. If the cause of inoperability exists on the other DG, it is declared inoperable upon discovery, and Condition D of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, SR 3.8.1.2 can be performed within the same Completion Time as Required Action B.3 to provide assurance of continued OPERABILITY of the remaining DG.

Conversely, Required Action B.3 may be satisfied by a simple review when the cause of the initial inoperability is pre-planned, preventive maintenance and testing. It is also permissible to perform elective maintenance as part of the pre-planned, preventive maintenance. In this case, there is no potential for a common cause failure, as no failure has occurred. At any point during the pre-planned maintenance or testing, if any new failure is detected, which on its own would cause the EDG to be inoperable and was not maintenance induced, the common cause evaluation must be re-performed on the Operable DG. If the 24 hour Completion Time for Required Action B.3 has expired at the point of discovery of the failure requiring corrective maintenance, Condition E must be entered until the common cause evaluation or SR 3.8.1.2 is performed.

(continued)

BASES

ACTIONS

B. 3 (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing B.3, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG

B.4

To ensure the continued OPERABILITY of the remaining DG during the 7 day Completion Time of Required Action B.5, SR 3.8.1.2 must be performed once per 72 hours for the OPERABLE DG. The 72 hour Completion Time is acceptable since it has already been determined that a common cause failure does not exist.

Required Action B.4 is modified by a Note that removes this requirement when the cause of the initial inoperability is pre-planned, preventive maintenance and testing. It is also permissible to perform elective maintenance as part of the pre-planned preventive maintenance. In this case, no actual failure has occurred (i.e., a potential for a common mode failure has not been identified) and the likelihood of the other DG having an undetected failure during this period is low. At any point during the pre-planned maintenance, if any new failure requiring corrective maintenance is detected, i.e., which on its own would cause the EDG to be inoperable and was not maintenance induced, Required Action B.4 must be entered for the Operable DG. If the 72 hour Completion Time has expired at the point of discovery of the failure requiring corrective maintenance, then Corrective E must be entered until SR 3.8.1.2 is performed.

B.5

In Condition B, the remaining OPERABLE DG and offsite circuit(s) are adequate to supply electrical power to the onsite Class 1E Distribution System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS

B.5 (continued)

The second Completion Time for Required Action B.5 establishes a limit based on the maximum time allowed for the combination of one DG and two offsite AC power sources to be inoperable during any single contiguous occurrence of failing to met the LCO except for Action A. If Condition B is entered while, for instance, two offsite circuits are inoperable and one circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 24 hours. This situation could lead to a total of 8 days, since initial failure of the LCO (except for Condition A), to restore the DG. At this time, the second offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 24 hours (for a total of 9 days) allowed prior to complete restoration of the LCO (except for Condition A). The 8 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B and C are entered concurrently, and when corrective actions are completed prior to completing the shutdown required by LCO 3.0.3 (which is required to be entered by Action F). The "AND" connector between the 7 day and 8 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

C.1 and C.2

As noted above, this Condition is entered whenever the grid operator informs the DAEC that a unit trip could lead to degraded voltage conditions in the DAEC Switchyard (Ref. 4).

Required Action C.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with inoperability of two offsite circuits. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is 12 hours. When a concurrent redundant required feature failure exists, a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions, (i.e., single division systems are not included in the list). Redundant required features failures consist of any of these features that are inoperable because any

(continued)

BASES

ACTIONS C.1 and C.2 (continued)

inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All offsite circuits are inoperable; and

b. A required feature is inoperable.

If, at any time during the existence of this Condition (two offsite circuits inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the Offsite Electrical Power System does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC Electrical Power System that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

With both of the offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time in Required Action C.2 provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC Electrical Power System capable of meeting its design criteria.

According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

The second Completion Time for Required Action C.2 establishes a limit based on the maximum time allowed for the combination of one DG and two offsite AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO except for Condition A. If Condition C is entered while, for instance, one DG is inoperable and the DG is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 8 days, since initial failure of the LCO (except for Condition A), to restore one of the two inoperable offsite circuits. At this time, a DG could again become inoperable, one offsite circuit restored OPERABLE, and an additional 7 days (for a total of 15 days) allowed prior to complete restoration of the LCO (except for Condition A). The 8 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B and C are entered concurrently, and when corrective actions are completed prior to completing the shutdown required by LCO 3.0.3 (which is required to be entered by Action F). The "AND" connector between the 24 hours and 8 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

BASES

ACTIONS

C. 1 and C.2 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met (except for condition A), instead of the time that Condition C was entered.

D.1

With two DGs inoperable, there is no remaining standby AC source. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation. According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

E.1 and E.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

F.1

Condition F corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC Electrical Power System will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with UFSAR Section 3.1.2.2.9 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are largely in accordance with the recommendations of Safety Guide 9 as discussed in UFSAR Section 1.8.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10) or as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is generally applicable. The minimum steady state output voltage of 3744 V is approximately 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. This value also provides a large margin of safety, since safety related motors are capable of accelerating their loads at 70% of rated voltage (2912 V or 322 V). The specified maximum steady state output voltage of 4576 V or 110% of 4160 V is less than the maximum operating voltage specified for 4000 V motors (4756 V), and therefore also provides ample margin. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 59.5 Hz and 60.5 Hz, respectively. These values are approximately equal to ± 1% of the 60 Hz nominal frequency and are conservative with respect to the recommendations found in Regulatory Guide 1.9 (Ref. 17).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that at least the minimum required offsite power supply breakers are in their correct position to ensure that distribution buses and loads are connected to either the preferred power source or the alternate preferred power source and that appropriate independence of offsite circuits is maintained. This can be accomplished by verifying that an essential bus is energized, and that the status of offsite supply breakers that are displayed in the control room are correct. The status of manual disconnects is verified administratively. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and (for SR 3.8.1.2 only) followed by a warmup prior to loading. Note 3 to SR 3.8.1.2 allows delaying the entry into associated Conditions and Required Actions for up to two hours during the performance of the conditional surveillance required by Required Actions B.3 or B.4. This Note is necessary because to perform a slow start and warmup of the DG requires reducing the governor control setting to minimum and securing the generator field excitation. The governor control setting is gradually increased to bring the DG to synchronous speed and to allow for warmup. Once the DG is at synchronous speed, the generator field excitation is enabled and the DG is again capable of supplying the essential bus. During this warmup portion of the surveillance test, the DG is incapable of supplying the essential bus and is considered inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

After completion of the SR, the fuel racks to the DG are disabled to allow purging of any residual fuel oil from the cylinders. This also renders the DG inoperable. The two hours allowed by the Note minimizes the amount of time a DG is inoperable while providing enough time to perform the required Conditional Surveillance and avoids entering the shutdown actions of Condition E or F unnecessarily.

For the purposes of this testing, the DGs are manually started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines during testing, the manufacturer of the DGs installed at the DAEC recommends a modified start in which the starting speed of the DG is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2 (SR 3.8.1.2).

SR 3.8.1.7 requires that DG starts from standby conditions and achieves required voltage and frequency (i.e. - voltage $\geq$ 3744 V and frequency $\geq$ 59.5 Hz) within 10 seconds; and achieves steady state voltage $\geq$ 3744 V and $\leq$ 4576 V and frequency $\geq$ 59.5 Hz and $\leq$ 60.5 Hz. The 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section 15.2.1 (Ref. 12). The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The normal Frequency for SR 3.8.1.2 is consistent with Safety Guide 9. The Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and can be manually loaded to ≥ 2750 kW and ≤ 2950 kW, providing a 200 kW range centered on the continuous duty rating of the DGs of 2850 kW. This range ensures that the DGs are tested at a load above the maximum expected accident load. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor greater than 0.9 lagging. While a value of 0.8 is the design rating of the machine, the machine is operated at power factors greater than 0.9 for normal operations and greater than 0.8 for surveillance testing. The load limit is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The normal Frequency for this Surveillance is consistent with Safety Guide 9.

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test.

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which the day tank low level alarm is annunciated. This low level alarm should only be received if the automatic fuel oil transfer instrumentation is not functioning properly. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of approximately one hour of DG operation at full load, considering a conservative fuel consumption rate. Verification that at least a one hour supply of fuel oil exists in a day tank provides assurance that a DG can operate continuously, and also allows the operating crew sufficient time to take corrective action should the automatic fuel oil transfer system not function properly.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

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. Testing for water content and removal of water from the fuel oil day tanks as necessary, 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 breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water, as necessary, minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequencies meet the intent of Regulatory Guide 1.137 (Ref. 10). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for manual fuel transfer systems are OPERABLE. Additional assurance of fuel oil transfer pump OPERABILITY is provided by meeting the testing requirements for pumps that are contained in the ASME Code (Ref. 13). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

The slow transfer of each 4.16 kV essential bus power supply from the preferred offsite circuit (i.e. - the startup transformer) to the alternate preferred offsite circuit (i.e. the standby transformer) demonstrates the OPERABILITY of the alternate preferred circuit distribution network to power the shutdown loads. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the Electrical Distribution Systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and the capability to reject the largest single load and return to the required voltage and frequency (i.e. - voltage $\geq$ 3744 V and $\leq$ 4576 V and frequency $\geq$ 59.5 Hz and $\leq$ 60.5 Hz) within predetermined periods of time (i.e., 1.3 seconds for voltage and 3.9 seconds for frequency) while maintaining an acceptable margin to the overspeed trip. The largest single load for each DG is a core spray pump motor (700 hp). This Surveillance may be accomplished by tripping its associated single largest post-accident load with the DG solely supplying the bus.

As specified by IEEE-308 (Ref. 14), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For both DGs, this represents 64.5 Hz, equivalent to 75% of the difference between nominal speed and the overspeed trip setpoint.

The time, voltage, and frequency tolerances specified in the Bases for this SR are derived from UFSAR Table 8.3-1 (Ref. 16) recommendations for response during load sequence intervals. The voltage and frequency are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are the steady state voltage and frequency to which the system must recover following load rejection within a predetermined time period. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the Electrical Distribution Systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature and low lubricating oil pressure) are bypassed on either an ECCS initiation test signal or a LOOP test signal and critical protective functions (engine overspeed and generator differential current) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and LOOPs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

As specified by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the individual pump timers are reset.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Under either LOCA conditions or during a loss of offsite power, loads are sequentially connected to the bus by a timed logic sequence using individual time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. Verifying the load sequence time interval is greater than or equal to 2 seconds ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load. The Allowable Values for the Core Spray and Low Pressure Coolant Injection Pump Start - Time Delay Relays, Table 3.3.5.1-1, Functions 1.e and 2.e, ensure this time interval is maintained as well as ensuring that safety analysis assumptions regarding ESF equipment time delays are not violated. Allowances for instrument inaccuracies in the load sequence time interval are also accounted for by the Pump Start - Time Delay Relay Allowable Value.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF Systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates DG operation during a Loss of Offsite Power actuation test signal (LOOP signal) in conjunction with an ECCS initiation signal (LOCA signal). This test verifies all actions encountered from the LOOP/LOCA, including the LOOP/LOCA load shedding function and energization of the essential buses and respective loads from the DG. This Surveillance also demonstrates the as-designed operation of the standby power sources during a LOOP, including: 1) de-energization of the essential buses, 2) the dead bus load shedding function, and 3) that the DG receives a start signal. This surveillance also demonstrates that the DG automatically starts from the design basis actuation signal (LOCA signal). It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency (i.e., voltage $\geq$ 3744 V and $\leq$ 4576 V and frequency $\geq$ 59.5 Hz and $\leq$ 60.5 Hz) within the specified time (10 seconds). In lieu of multiple demonstrations of DG starting and achieving the required voltage and frequency in the specified time from each of the various start signals (LOOP, LOCA and LOOP/LOCA), and operation for $\geq$ 5 minutes, testing that adequately shows the capability of the DG to start from each of the signals is acceptable. The DG auto-start time of 10 seconds is derived from requirements of the accident analysis, (Ref. 12), for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes (with a LOOP signal in conjunction with a LOCA signal present) in order to demonstrate that all of the starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or systems are not capable of being operated at full flow. In lieu of actual demonstration of connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that proper operation with each of the various signals present is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length. Operating experience has shown that these components usually pass the SR when performed at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove the required offsite circuit from service, perturb the Electrical Distribution System, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. UFSAR, Section 3.1.2.2.8.

2. UFSAR, Section 8.2.1.3 and Section 8.3.1.1.5

3. UFSAR, Section 1.8.9.

4. FPL letter, L-2006-073, dated April 3, 2006, Response to NRC Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power.

5. UFSAR, Chapter 15.

(continued)

BASES

REFERENCES (continued)

6. Regulatory Guide 1.93.

7. Generic Letter 84-15.

8. UFSAR, Section 3.1.2.2.9

9. Regulatory Guide 1.108.

10. Regulatory Guide 1.137.

11. [Deleted]

12. UFSAR, Section 15.2.1

13. ASME Code for Operation and Maintenance of Nuclear Power Plants.

14. IEEE Standard 308.

15. [Deleted]

16. UFSAR, Table 8.3-1.

17. Regulatory Guide 1.9.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources — Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources — Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shutdown the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODES 1, 2, and 3 LCO requirements are acceptable during shutdown MODES, based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operation MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (Diesel Generator (DG)) power.

The AC Sources – Shutdown satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems — Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with Distribution System essential bus required OPERABLE by LCO 3.8.8, ensures that a diverse power source is available for providing electrical power support assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the plant in a safe

(continued)

BASES

LCO (continued)

manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents). Automatic initiation of the required DG during shutdown conditions is specified in LCO 3.3.8.1, "LOP Instrumentation".

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective essential bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. The required offsite circuit consists of either: 1) either the incoming circuit breaker (1400) and disconnects (1401 and 1402) or incoming circuit breaker (2690) and disconnects (2691 and 2692), the overhead 161 kV buswork, circuit breaker (1590) and disconnect (1591), the Reserve Auxiliary Transformer (1X5), circuit breaker (8490) and disconnect (8491), the underground 34.5 kV line, the standby transformer (1X4), the 4160 volt supply line and the two supply circuit breakers (1A301 and 1A401) to essential buses 1A3 and 1A4, respectively, or 2) the incoming circuit breaker (5550 or 5560) and disconnect (5551 or 5555, respectively), the overhead 161 kV line, the startup transformer (1X3), one of the two 4160 volt supply lines and one of the two supply circuit breakers (1A302 or 1A402) to essential buses 1A3 or 1A4, respectively, if required by LCO 3.8.8.

The required DG must be capable of starting, accelerating to rated speed and voltage, connecting to its respective essential bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the essential buses. The necessary portions of Emergency Service Water are also required to provide appropriate cooling to each required DG.

Proper sequencing of loads, including non-essential load shedding capability, is a required function for DG OPERABILITY.

In addition, proper timed logic sequence operation, is an integral part of offsite circuit OPERABILITY since its inoperability could impact the ability to start and maintain energized loads required OPERABLE by LCO 3.8.8. No automatic transfer capability is required for offsite circuits to be considered OPERABLE during shutdown conditions.

(continued)

BASES (continued)

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems that provide core cooling are available;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Actions have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1

An offsite circuit is considered inoperable if it is not available to supply power to either of the essential buses. If both essential 4.16 kV buses are required per LCO 3.8.8, one division with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required

(continued)

BASES

ACTIONS

A.1 (continued)

features inoperable that are not powered from offsite power, appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

Required features remaining powered from a qualified offsite power circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action.

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3,

With the required offsite circuit not available to either division, the option still exists to declare all affected required features inoperable per required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to Immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of Immediately is consistent with the required times for ACTIONS requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3, (continued)

during which the plant safety systems may be without sufficient power. Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required essential bus, ACTIONS for LCO 3.8.8 must be Immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude deenergizing a required 4160 V essential bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE.

Note 2 states that SR 3.8.1.13 is considered to be met without the ECCS initiation signals OPERABLE when the ECCS initiation signals are not required to be OPERABLE per Table 3.3.5.1-1. This SR demonstrates the DG response to an ECCS signal (either alone or in conjunction with a loss-of-power signal). This is consistent with the ECCS instrumentation requirements of Table 3.3.5.1-1 that do not require the ECCS signals to be OPERABLE in MODES 4 and 5 when ECCS is not required to be OPERABLE.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

The Diesel Generators (DGs) are provided with a storage tank having a fuel oil capacity sufficient to operate one DG for a period of 7 days while the DG is supplying maximum post Loss of Coolant Accident (LOCA) load demand discussed in UFSAR, Section 9.5.4 (Ref. 1) and Regulatory Guide 1.137 (Ref. 2). The maximum load demand is calculated using the assumption that only one DG is available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from storage tank to the day tanks by either of two transfer pumps. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe or valve, to result in the loss of more than one DG. The outside tanks, pumps, and piping are located underground.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity (or Saybolt Universal Viscosity), specific gravity (or API gravity), and total particulate contamination.

The DG Lubrication System is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The DG Lube Oil System is designed to provide automatic lube oil makeup to the DG crankcase for a minimum of 7 days of operation per UFSAR Section 8.3.1 (Ref. 7). This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has two independent starting air supply systems each with adequate capacity for five successive normal start attempts per air receiver without recharging. A minimum of fifteen normal DG starts are provided for each DG per UFSAR Section 8.3.1 (Ref. 7).

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) Systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an Abnormal Operational Transient or a postulated DBA with loss of offsite power. DG day tank fuel oil requirements, as well as transfer capability from the storage tank to the day tanks, are addressed in LCO 3.8.1, "AC Sources — Operating," and LCO 3.8.2, "AC Sources — Shutdown."

The starting air system is required to have a minimum capacity for five successive normal DG start attempts without recharging the air start receivers.

(continued)

BASES (continued)

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an Abnormal Operational Transient or a postulated DBA. Because stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG for Conditions B, E, and F. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. The fuel oil level equivalent to a 6 day supply is 32,689 gallons. These circumstances may be caused by events such as:

a. Full load operation required for an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will

(continued)

BASES

ACTIONS

A.1 (continued)

be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

In this Conditions, the 7 day lube oil inventory, i.e., sufficient lube oil to support 7 days of continuous DG operation at full load conditions is not available. However, the Condition is restricted to lube oil level reductions that maintain at least a 6 day supply. The lube oil inventory equivalent to a 6 day supply is 221 gallons. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a period prior to declaring both DGs inoperable. The 30 day Completion Time starts when initial analysis results are known and allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that

(continued)

BASES

ACTIONS

D.1 (continued)

the mixture of new fuel oil and previously stored fuel oil remains acceptable, or to restore the stored fuel oil properties. If testing of the new fuel oil reveals fuel oil properties are not within limits, those properties not within limits must be tested, or restored to within limits. This restoration may involve feed and bleed procedures, filtering, or combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function. Note that when the entire inventory of stored fuel oil is replaced with new fuel oil, the new fuel oil properties must be within specification prior to declaring the DGs OPERABLE.

E.1

With all starting air receivers associated with a DG with pressure < 150 psig, sufficient capacity for five successive DG start attempts may not exist. However, as long as any one receiver's pressure is ≥ 75 psig, there is adequate capacity for at least one start attempt (as shown during initial plant startup testing when successful DG starting was demonstrated with air receiver pressure as low as 50 psig), and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tank to support a single DG's operation for 7 days at full load. The fuel oil level equivalent to a 7 day supply is 37,967 gallons when calculated in accordance with References 2 and 3. The required fuel storage volume is determined using the most limiting energy content of the stored fuel. Using the known correlation of diesel fuel oil absolute specific gravity or API gravity to energy content, the required diesel output, and the corresponding fuel consumption rate, the onsite fuel storage volume required for 7 days of operation can be determined. SR 3.8.3.3 requires new fuel to be tested to verify that the absolute specific gravity or API gravity is within the range assumed in the diesel fuel oil consumption calculations. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lubricating oil inventory is available to support at least 7 days of full load operation for each DG. The lube oil inventory equivalent to a 7 day supply is 257 gallons and is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from the lube oil makeup tank to the DG. The requirement is considered to be fulfilled by observing that the DG lube oil sump level is maintained in the normal band by the lube oil sump level controller.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. A Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

The tests listed below are a means of determining that the new and stored fuel oil has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tank without concern for contaminating the entire volume of fuel oil in the storage tank. These tests are to be conducted prior to adding the new fuel to the storage tank, but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D975-77 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D1298-85 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of $\geq$ 0.83 and $\leq$ 0.89 or an API gravity at 60°F of $\geq$ 28° and $\leq$ 38°;

c. Verify in accordance with ASTM D975-77, using ASTM Test Method D88-81, that viscosity at 100°F is $\geq$ 32.6 and $\leq$ 40.1 Saybolt Universal Seconds;

d. Verify that water and sediment are within limits when tested in accordance with ASTM D975-77 (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tank.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-77 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-77 (Ref. 6), except that a cloud point limit of 0°C has been selected due to fuel oil being stored underground and below the frost line, and that flash point and cetane number are not required. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-89 (Ref. 6), Method A2 or A3. These methods involve a gravimetric determination of total particulate concentration in the fuel oil and have a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of any refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles per air receiver without recharging. The pressure specified in this SR is intended to reflect a conservative value for which the five starts can be accomplished, assuming only one air start receiver is pressurized.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and the Air Start System for each DG.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.5

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. Checking for the presence of water, and removing water, as necessary, 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 water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequencies are consistent with those recommended and established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the water is removed during performance of the Surveillance.

REFERENCES

1. UFSAR, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195, 1976.
4. [Deleted]
5. UFSAR, Chapter 15.
6. ASTM Standards: D975-77, D1298-85 and D2276-89.
7. UFSAR, Section 8.3.1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources — Operating

BASES

BACKGROUND

The DC Electrical Power System provides the AC Emergency Power System with control power. It also provides both motive and control power to selected safety related equipment. As discussed in UFSAR Section 3.1.2.2.8 (Ref. 1), the DC Electrical Power System is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC Electrical Power System also conforms to the intent of the recommendations of Safety Guide 6, as discussed in UFSAR Section 1.8.6. (Ref. 2) and IEEE-308 (Ref. 3).

The station service DC power sources provide both motive and control power to selected safety related equipment, as well as circuit breaker control power for some of the 4160 V, and all 480 V and lower, AC Distribution Systems. Each 125 VDC subsystem is energized by one 125 V station service battery and two 125 V battery chargers (one normally inservice charger and one swing charger that is able to separately charge either 125 VDC divisional battery). The 250 VDC subsystem can be energized by either of two 250 V battery chargers. Each battery is exclusively associated with a single 125 V or 250 VDC bus. The normal chargers are supplied from the same essential AC load groups for which the associated DC subsystem supplies the control power, while the swing 125 VDC charger can be supplied from either essential AC division and the two redundant 250 VDC chargers are supplied from separate essential AC divisions. The loads between the redundant 125 VDC subsystems are not transferable except for the 'B' actuation logic of the Automatic Depressurization System, which is normally powered from the Division 2 DC System, but which will automatically be powered from the Division 1 DC System if normal power is lost. The 125 VDC subsystems also provide control and instrumentation power for their respective DG.

(continued)

BASES

BACKGROUND (continued)

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system, acting as a voltage regulator. If a battery is disconnected from its distribution bus and only a charger is supplying bus voltage, the associated Distribution System shall be considered inoperable, as it cannot supply the peak power required for some event scenarios.

In case of loss of power to any battery charger, the DC loads are automatically powered from the battery until the redundant charger or swing charger is placed in service by operator action.

The DC Power Distribution System is described in more detail in Bases for LCO 3.8.7, "Distribution System — Operating," and LCO 3.8.8, "Distribution System — Shutdown."

Each battery (with a minimum of 59 cells for the 125 VDC batteries and 115 cells for the 250 VDC battery) has adequate storage capacity to carry the control and essential instrumentation power continuously for approximately 4 hours and the emergency motor loads for their required length of time.

Each DC battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels except for the swing 125 VDC battery charger which is mechanically interlocked to prevent being simultaneously connected to both distribution buses with double isolation circuit breakers.

The batteries for DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at the end of a nominal 20 year service cycle. The expected life of the batteries may exceed 20 years and will be adjusted based on engineering evaluations of each battery's capacity trend data as the batteries age. The minimum design voltage limits are 105V and 210V for the 125 VDC and 250 VDC subsystems, respectively.

(continued)

BASES

BACKGROUND (continued)

Each battery charger of DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each station service battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully charged state while supplying normal steady state loads (Ref. 10).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 15 (Ref. 5), assume that Engineered Safety Feature (ESF) Systems are OPERABLE. The DC Electrical Power System provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power subsystems — with: 1) Division I and Division II 125 VDC subsystems, each consisting of one 125 V battery, the associated battery charger or the swing battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, and 2) the 250 VDC subsystem consisting of one battery bank, one of the two battery chargers, and the corresponding control equipment and interconnecting cabling are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an Abnormal Operational Transient or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 10).

(continued)

BASES

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of Abnormal Operational Transients; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 4 and 5 and other conditions in which the DC electrical power sources are required are addressed in the Bases for LCO 3.8.5, "DC Sources — Shutdown."

ACTIONS

A.1

Condition A represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected Division. The 8 hour limit is consistent with the allowed time for an inoperable DC Distribution System division.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. (In fact, loss of one Division of 125 VDC power is the most limiting single failure assumed in the accident analysis. The effect of a loss of a single Division of 125 VDC on the performance of the ECCS has been evaluated and found to be acceptable.) Since a subsequent worst case single failure could, however, result in the

(continued)

BASES

ACTIONS

A.1 (continued)

loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 8 hours. The 8 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable 125 VDC electrical power subsystem and, if the 125 VDC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

An Revision was approved to revise the completion time for required action 3.8.4.A.1 from 8 hours to 10 days on a one-time basis to allow replacement of station batteries 1D1 and 1D2 while at power.

This one-time change also requires that required features be declared inoperable when the associated 125 VDC source is inoperable and the redundant required feature(s) are also inoperable for at least four hours. This action is intended to provide assurance that a loss of onsite power, during the period that a 125 VDC source is inoperable, does not result in a complete loss of safety function of critical systems. The completion time is intended to allow the operator time to evaluate and repair any discovered inoperabilities.

A temporary battery will be connected to the associated bus during the replacement activity. This temporary battery will be assembled from safety-related, Class 1E cells but will not be seismically mounted due its location in the turbine building. There will be a 10-day replacement period for battery 1D1 and a separate 10-day replacement period for battery 1D2.

B.1 and B.2

If the station service 125 VDC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

is consistent with the time suggested in Regulatory Guide 1.93 (Ref. 6).

C.1

With the 250 VDC electrical power subsystem inoperable, the HPCI System and associated PCIVs may be incapable of performing their intended function and must be immediately declared inoperable. The associated PCIVs referred to are: the RHR-SDC Isolation Valve (MO-1909), the RWCU Inlet Outboard Isolation Valve (MO-2701), the HPCI Steam Supply Isolation Valve (MO-2239), the HCPI Feedwater Injection Isolation Valve (MO-2312), and Main Steam Drain Line Isolation Valve (MO-4424).

D.1

Condition D corresponds to a level of degradation in the DC Electrical Power System that either causes a required safety function to be lost (e.g. when Division I and Division II of the 125 VDC electrical power subsystem are inoperable) or that results in a level of degradation that is severe enough to warrant an immediate shutdown (e.g. when one Division of the 125 VDC electrical power subsystem is inoperable concurrent with the 250 VDC electrical power subsystem being inoperable). When this situation exists, the plant may be in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled plant shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and 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 (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

the nominal design voltage of the battery and are consistent with the manufacturer's minimum float voltage recommendations (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is consistent with manufacturer recommendations and with the intent of IEEE-450 (Ref. 7).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The connection resistance limits established for this SR must be no more than 20% above the resistance as measured during installation or not above the ceiling value established by the manufacturer. The resulting limits are 5.0 E-5 ohms for inter-cell connections and 1.4 E-4 ohms for inter-rack connections, inter-tier connections and terminal connections. The Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is controlled under the Surveillance Frequency Control Program. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency for this SR is consistent with the intent of IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and rack integrity.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance. The connection resistance limits for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer. The resulting limits are 5.0 E-5 ohms for inter-cell connections and 1.4 E-4 ohms for inter-rack connections, inter-tier connections and terminal connections.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency of these SRs is consistent with the intent of IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 3). According to the recommendations of Regulatory Guide 1.32 (Ref. 8), the battery charger supply is required 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 occurences. The minimum required amperes ensures that these requirements can be satisfied. The minimum required voltage ensures that the requirements are satisfied at the minimum float voltage that the battery chargers are normally set for. Charger operation at an output greater than the minimum required voltage and amperage, such as during equalize mode,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

demonstrates the battery charger meets, and exceeds, the Surveillance Requirements.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance on a required battery charger would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. This Note does not preclude performance of this SR on the "spare" battery charger (i.e., a charger not in-service or "required"). This Note also acknowledges that credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.7

A battery service test 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 Reference 4. The voltage of each cell shall be determined after the discharge. Following discharge, battery cell parameters must be restored in accordance with LCO 3.8.6. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is consistent with the maximum length of an operating cycle.

This SR is modified by two Notes. Note 1 allows the performance of a performance discharge test in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would remove a required DC Electrical Power subsystem from service, perturb the Electrical Distribution System, and challenge safety systems. Credit may be taken for unplanned events that satisfy the SR.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance test is described in the Bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 7) and IEEE-485 (Ref. 9). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. The Frequency for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

this test is normally controlled under the Surveillance Frequency Control Program. However, if the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is $< 100\%$ of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity $\geq 100\%$ of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 7).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the Electrical Distribution System, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. Following discharge, battery cell parameters must be restored in accordance with LCO 3.8.6.

REFERENCES

1. UFSAR, Section 3.1.2.2.8.
2. UFSAR, Section 1.8.6.
3. IEEE Standard 308, 1971.
4. Calculations: CAL-E08-007 and CAL-E08-008, latest approved revisions.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93.
7. IEEE Standard 450, 1980.
8. Regulatory Guide 1.32, February 1977.
9. IEEE Standard 485, 1983.
10. UFSAR, Section 8.3.2

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources — Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources — Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 15 (Ref. 1), assume that Engineered Safety Feature Systems are OPERABLE. The 125 VDC Electrical Power System provides normal and emergency DC electrical power for the Diesel Generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation and during movement of irradiated fuel assemblies in the Secondary Containment.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The DC electrical power subsystems — with: Division I and Division II 125 VDC subsystems each consisting of one 125 V battery, the associated battery charger or the swing battery charger and the corresponding control equipment and interconnecting cabling supply power to the associated distribution system; and, the 250 VDC subsystem consisting of the 250V battery, one of the two battery chargers and the corresponding control equipment and interconnecting cabling sufficient to provide electrical power to the outboard RHR-SDC suction isolation valve (MO-1909), are required to be OPERABLE to support required DC distribution subsystems required OPERABLE by LCO 3.8.8, "Distribution Systems —Shutdown." This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide core cooling are available;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

(continued)

BASES (continued)

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Actions have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, and A.2.3

If more than one DC distribution subsystem is required according to LCO 3.8.8, the DC electrical power subsystems remaining OPERABLE with one or more DC electrical power subsystems inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowance of the option to declare required features inoperable with associated DC electrical power subsystems inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. However, in many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources — Operating," and LCO 3.8.5, "DC Sources — Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 15 (Ref. 2), assume Engineered Safety Feature Systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the Diesel Generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as discussed in the Bases for LCO 3.8.4 and LCO 3.8.5.

Since battery cell parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an Abnormal Operational Transient or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

(continued)

BASES (continued)

APPLICABILITY The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, parameters for required battery cells are only required to be within limits when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met or Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met for required battery cells (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits.

Continued operation is only permitted for 31 days before parameters for required battery cells must be restored to within Category A and B limits. Taking into consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected (required) cell, sufficient capacity to supply the maximum expected load requirement is not ensured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as any Required Action of Condition A and associated Completion Time not met or average electrolyte temperature of representative cells $\leq 65°F$, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1 (continued)

The SR should only be performed when the battery is on a float charge to allow obtaining meaningful, consistent, trendable readings. If the battery is on equalize charge or has been on equalize charge anytime during the previous 72 hours when the SR is due, performance of the SR should be delayed until the battery has been off equalize charge for 72 hours, utilizing the allowance of SR 3.0.2. If it is expected that a battery will need to be on equalize charge when the SR is due and past the extension time allowed by SR 3.0.2, the SR should be performed early before the battery is placed on equalize charge. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.2

The periodic inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). The actual Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In addition, within 24 hours of a battery discharge < 110 V for 125 V and < 220 V for 250 V or a battery overcharge > 150 V for 125 V and > 300 V for 250 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V for 125 V and ≤ 220 V for 250 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance that verifies the average temperature of representative cells is within limits is consistent with a recommendation of IEEE-450 (Ref. 3) that states that the temperature of electrolytes in representative cells should be determined on a routine basis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer's recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Table 3.8.6-1

This Table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperature and charge effects. In addition to this allowance, footnote (a) to Table 3.8.6-1 permits the electrolyte level to be temporarily above the specified maximum level during an equalizing charge, provided it is not overflowing. It is acknowledged that, following completion of an equalizing charge, electrolyte level may temporarily be above the specified limit, but not overflowing, for a short period of time. The recovery time for electrolyte level after the equalizing charge is considered part of the equalizing process. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is $\geq$ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 3), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells. The Category A limit specified for specific gravity for each pilot cell is $\geq$ 1.195 (0.015 below the manufacturer's fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref 3), the specific gravity readings are based on a temperature of 77°F (25°C).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is $\geq$ 1.190 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells 1.200 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C Limit for voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category C limit on average specific gravity $\geq$ 1.190, is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote (b) of Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current, while on float charge, is $<$ 2 amps for station service batteries. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days, each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. [Deleted]

2. UFSAR, Chapter 15.

3. IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems — Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC essential bus electrical power distribution subsystems.

The primary AC Distribution System consists of two 4.16 kV essential buses each having an offsite source of power as well as a dedicated onsite Diesel Generator (DG) source. Each essential bus is normally connected to the startup transformer (1X3). During a loss of the normal offsite power source to the essential buses, the alternate supply breaker from the standby transformer (1X4) attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the essential buses.

The secondary plant distribution system includes 480 VAC emergency buses 1B3 and 1B4 and associated load centers, and transformers.

There are two independent 125 VDC electrical power distribution subsystems and one independent 250 VDC electrical power distribution subsystem that support the necessary power for ESF functions.

The list of required distribution buses is presented in Table B 3.8.7-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 15 (Ref. 1), assume ESF Systems are OPERABLE. The AC and DC Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Cooling (RCIC) System; and Section 3.6 Containment Systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the AC and DC Electrical Power Distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst case single failure.

The AC and DC Electrical Power Distribution System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an Abnormal Operational Transient or a postulated DBA. The AC and DC electrical power distribution subsystems listed in the LCO are required to be OPERABLE. For the purposes of this LCO, the Intake Structure electrical power distribution subsystems (LCO 3.8.7.d) are not considered part of the Division I and Division II AC electrical power distribution subsystems (LCO 3.8.7.a), and the 125 VDC RCIC Motor Control Center (LCO 3.8.7.e) is not considered part of the Division I and Division II 125 VDC electrical power distribution subsystems (LCO 3.8.7.b).

Maintaining the Division 1 and 2 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF function is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC electrical power distribution subsystems require the associated buses and electrical circuits to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or battery and charger combination.

(continued)

BASES

LCO (continued)

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.7-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other buses, such as motor control centers (MCC) and distribution panels which help comprise the AC and DC distribution systems may not be listed in Table B 3.8.7-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., loss of a 4.16 kV essential bus, which results in de-energization of all buses powered from the 4.16 kV essential bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV essential bus).

In addition, tie breakers between redundant safety related AC and DC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystems) are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV essential buses from being powered from the same offsite circuit.

(continued)

BASES (continued)

APPLICABILITY The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of Abnormal Operational Transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 and other Conditions in which AC and DC electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.8, "Distribution Systems — Shutdown."

ACTIONS A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels inoperable (except for the intake structure electrical power distribution subsystems, which are covered by Action D.1), and a loss of function has not yet occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one Division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining Division by stabilizing the unit, and on restoring power to the affected Division.

(continued)

BASES

ACTIONS

A.1 (continued)

The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for combinations of either Division I and Division II AC or Division I and Division II DC (LCO 3.8.7.a or 3.8.7.b) required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, this LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 16 hours, since initial failure of the LCO, to restore the AC electrical power distribution system. At this time a DC bus could again become inoperable, and AC electrical power distribution system could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time this LCO was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more essential Division I or Division II 125 VDC electrical power distribution subsystems inoperable, (except for 1D14, the motor control center serving the RCIC System, which is covered by Action F.1), and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. (In fact, loss of one Division of 125 VDC power is the most limiting single failure assumed in the accident analysis.) The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystems must be restored to OPERABLE status within 8 hours by powering the bus from the associated battery or charger.

Condition B represents one or more DC buses without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected Division.

This 8 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 8 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power, while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division;

(continued)

BASES

ACTIONS

B.1 (continued)

c. The potential for an event in conjunction with a single failure of a redundant component;

d. The fact that this condition has specifically been analyzed as the most limiting single failure in the accident analysis, and found to be acceptable.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combinations of either Division I and Division II AC or Division I and Division II VDC (LCO 3.8.7.a or 3.8.7.b) required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 16 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC bus could again become inoperable, and DC electrical power distribution system could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

With either one or both of the essential 480 VAC buses that serve the intake structure (1B9 or 1B20) inoperable, the River Water Supply (RWS) subsystem powered from the applicable bus is not capable of performing its intended function. Immediately declaring the associated RWS subsystem(s) inoperable allows the Actions of LCO 3.7.2, “RWS System and Ultimate Heat Sink”, to apply appropriate limitations on continued reactor operation.

E.1

With a distribution panel or MCC in the 250 VDC electrical power distribution subsystem inoperable, the equipment powered from the inoperable distribution panel or MCC are not capable of performing their intended functions. Immediately declaring the associated supported features inoperable allows the Actions of the associated LCOs (LCO 3.5.1, “ECCS Operating”, and LCO 3.6.1.3, “Primary Containment Isolation Valves”) to apply appropriate limitations on continued reactor operation. For example, if distribution panel 1D40 is inoperable, MO-1909, MO-2701, MO-4424, MO-2312, and MO-2239 should be declared inoperable, and the HPCI System should be declared inoperable. If MCC 1D41 is inoperable, the HPCI System should be declared inoperable, and MO-2239 and MO-2312 should be declared inoperable. If MCC 1D42 is inoperable, MO-1909, MO-2701, and MO-4424 should be declared inoperable.

(continued)

BASES

ACTIONS (continued)

F.1

With the 125 VDC RCIC MCC inoperable, the equipment powered from the inoperable MCC are not capable of performing their intended functions. Immediately declaring the RCIC System and the outboard RCIC steam line isolation valve (MO-2401) inoperable allows the Actions of the associated LCOs (LCO 3.5.3, “RCIC System”, and 3.6.1.3, “Primary Containment Isolation Valves”) to apply appropriate limitations on continued reactor operation.

G.1

Condition G corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one AC or DC electrical power distribution subsystem is lost, and this results in the loss of a required function (except as allowed by Condition D), the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verifying the absence of low voltage alarms, or by verifying a load powered from the bus is operating. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.7.2

This Surveillance verifies the "break-before-make" coordination of the circuit breakers for the LPCI Swing Bus (1B34A and 1B44A). This SR, when coupled with SR 3.5.1.7, demonstrates the ability of the LPCI Swing Bus to perform its intended safety function in support of the LPCI Loop Select design without compromising the independence of the AC Electrical Power Distribution System (Reference 2). Consequently, failure to satisfy this SR requires that both 1B34 and 1B44 buses be declared inoperable, and Condition G be entered until either 1B34 or 1B44 can be isolated from the Swing Bus, as a loss of all low pressure ECCS has potentially occurred. If the Swing Bus can be isolated from 1B34 or 1B44, then this SR is met, and the AC electrical power distribution subsystems are not inoperable. However, this will result in a failure to meet SR 3.5.1.7 (and Condition B of LCO 3.5.1 will be required to be entered since the LPCI system will be inoperable).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.

2. J. Hall (NRC) to L. Liu (IELP), "LPCI Swing Bus Design Modification (TAC No. 69556)," dated January 19, 1989

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[(a)]	DIVISION 2[(a)]
AC safety buses	4160 V	Essential Bus 1A3	Essential Bus 1A4
	480 V	Load Centers 1B3, 1B9	Load Centers 1B4, 1B20
	480 V	Motor Control Centers 1B32, 1B34	Motor Control Centers 1B42, 1B44
125 VDC buses	125 V	Distribution Panels 1D10, 1D11, 1D13 RCIC Motor Control Center 1D14	Distribution Panels 1D20, 1D21, 1D23
250 VDC buses	250 V	N/A	Distribution Panel 1D40 Motor Control Centers 1D41 and 1D42

[(a)] Each division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems — Shutdown

BASES

BACKGROUND

A description of the AC and DC Electrical Power Distribution System is provided in the Bases for LCO 3.8.7, "Distribution Systems — Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 15 (Ref. 1), assume Engineered Safety Feature (ESF) Systems are OPERABLE. The AC and DC Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC Electrical Power Distribution System is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the Electrical Distribution System necessary to support OPERABILITY of Technical Specifications required systems, equipment, and components — both specifically addressed by their own LCO, and implicitly required by the definition of OPERABILITY. In addition, it is acceptable for required buses to be cross-tied during shutdown conditions, permitting a single source to supply multiple redundant buses, provided the source is capable of maintaining proper frequency (if required) and voltage.

Maintaining these portions of the Distribution System energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems that provide core cooling;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

(continued)

BASES

APPLICABILITY (continued)

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Actions have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

Although redundant required features may require redundant Divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made, (i.e., to suspend CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment).

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Not withstanding performance of the above conservative Required Actions, a required Residual Heat Removal-Shutdown Cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.3 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.4 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the correct circuit breaker alignment. The correct circuit breaker alignment ensures power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to serve as a backup to procedural core reactivity controls to prevent the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

One channel of instrumentation is provided to sense the position of the refueling platform, the loading of the refueling platform fuel grapple, and the full insertion of all control rods. Additionally, inputs are provided for the loading of the refueling platform frame mounted hoist, the loading of the refueling platform monorail mounted hoist and the full retraction of the fuel grapple. With the reactor mode switch in the Shutdown or Refuel position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block in the Reactor Manual Control System (RMCS) to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform or any of its hoists are physically located

(continued)

BASES

BACKGROUND (continued)

over the reactor vessel. All refueling hoists have switches that open at a load lighter than the weight of a single fuel assembly in water.

The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the UFSAR analyses for the control rod removal error during refueling (Ref. 3) and the fuel assembly insertion error during refueling (Ref. 4). These analyses evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading of fuel into the core with any control rod withdrawn or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core such that, considering maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling Equipment Interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To prevent criticality during refueling, the refueling interlocks associated with the Refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

(continued)

BASES

LCO (continued)

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel loaded, the refueling platform trolley frame mounted hoist fuel loaded, the refueling platform monorail mounted hoist fuel loaded, and the refueling platform fuel grapple fully retracted position inputs are required to be OPERABLE. These inputs are combined in logic circuits, which provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are required to be OPERABLE during in-vessel fuel movement only on the equipment which will be used to move fuel when the reactor mode switch is in the Refuel position. The interlocks are not required when the reactor mode switch is in the Shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawals cannot occur simultaneously with in-vessel fuel movements.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and CORE ALTERATIONS are not possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

A.1

With one or more of the required refueling equipment interlocks inoperable (does not include the one-rod-out interlock addressed in LCO 3.9.2), the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 7.6.2.
3. UFSAR, Section 15.1.4.3.
4. UFSAR, Section 15.1.4.4.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn.

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Reactor Manual Control System).

This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refuel position one-rod-out interlock is explicitly assumed in the UFSAR analysis for the control rod withdrawal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

The refuel position one-rod-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" prevent criticality by preventing withdrawal of more than one control rod. With

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

one control rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

The Refuel Position One-Rod-Out Interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE and the reactor mode switch must be locked in the Refuel position to support the OPERABILITY of these channels. Since the DAEC design includes only one full-in indication (i.e., one reed switch for each control rod) that feeds both one-rod-out channels, another full-in indication may be used to temporarily provide input to both one-rod-out channels, using appropriate administrative controls. Under those conditions, this LCO is considered to be met, even though the full-in indication provided by design may not be functioning properly for a particular control rod. However, this normal full-in indication must be removed from providing input into the one-rod-out channels.

APPLICABILITY

In MODE 5, with the reactor mode switch in the Refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and the control rods (LCO 3.1.3, "Control Rod Operability") provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the Shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one or both channels of the refueling position one-rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

Control rod withdrawal must be Immediately suspended, and action must be Immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refueling position one-rod-out interlock requires the reactor mode switch to be in Refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refueling position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the switch while the reactor mode switch is positioned in Refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator to control rods not fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 7.6.2.
3. UFSAR, Section 15.1.4.3.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND

Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") or the control rod block with the reactor mode switch in the Shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation").

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "Shutdown Margin (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod withdrawal error during refueling in the UFSAR (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3) assumes all control rods are fully inserted. Thus, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality.

Control Rod Position satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.

APPLICABILITY

During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.

ACTIONS

A.1

With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the UFSAR. All fuel loading operations must be Immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into consideration the procedural controls on control rod movement during refueling as well as the redundant functions of the refueling interlocks.

(continued)

BASES (continued)

REFERENCES 1. UFSAR, Section 3.1.2.3.7.

2. UFSAR, Section 15.1.4.3.

3. UFSAR, Section 15.1.4.4.1.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication for each control rod provides necessary information to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") use the full-in position indication to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the withdrawal of any other control rod. The all-rods-in interlocks provide the signals, one to each of the two Reactor Manual Control System rod block logic circuits.

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "Shutdown Margin (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3) assumes all control rods are fully inserted. The full-in position indication is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time.

Control Rod Position Indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Each control rod full-in position indication must be OPERABLE to provide the required input to the refueling interlocks. The position indication is OPERABLE if it provides correct position indication to the refueling interlock logic.

APPLICABILITY

During MODE 5, the control rods must have OPERABLE full-in position indications to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the Shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A Note has been provided to modify the ACTIONS related to control rod position indication. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable control rod position indications provide appropriate compensatory measures for separate inoperable position indications. As such, this Note has been provided, which allows separate Condition entry for each inoperable required control rod position indication.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more required full-in position indications inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by Immediately suspending in-vessel fuel movement and control rod withdrawal, and Immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, Actions must be Immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicator(s) and electrically or hydraulically disarm the drive(s) to ensure that the control rod is not withdrawn. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. A control rod can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indications provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are actuated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indications is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. The full-in position indication is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1 (continued)

rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.

2. UFSAR, Section 15.1.4.3.

3. UFSAR, Section 15.1.4.4.1.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY - Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operations. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), the SDM (LCO 3.1.1, "Shutdown Margin (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analyses for the control rod withdrawal error during refueling (Ref. 2) and the fuel assembly insertion error (Ref. 3) evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur.

Control rod OPERABILITY - Refueling satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is $\geq$ 940 psig and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore are not required to be OPERABLE.

APPLICABILITY

During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in the Shutdown position and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

A.1

With one or more withdrawn control rods inoperable, action must be Immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is $\geq$ 940 psig.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.3 and SR 3.0.4.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 15.1.4.3.
3. UFSAR, Section 15.1.4.4.1.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level in the reactor vessel cavity. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Ref. 1). Sufficient iodine activity would be retained to limit offsite doses from the accident to less than Regulatory Guide 1.183 limits.

APPLICABLE SAFETY ANALYSES

During movement of fuel assemblies or handling of control rods, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment. A minimum water level of 23 ft allows a decontamination factor of 100 to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory.

Analysis of the fuel handling accident inside containment is described in Reference 1. With a minimum water level of 23 ft and a minimum decay time of 60 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and that offsite doses are maintained within allowable limits (Ref. 2).

RPV Water Level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

A minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits. The minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV is conservative with respect to the corresponding water level of 36 ft in the Spent Fuel Pool (SFP) (Reference LCO 3.7.8, "Spent Fuel Storage Pool Water Level") for ensuring adequate fission product scrubbing and retention if a fuel assembly is dropped and damaged.

APPLICABILITY

LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.8, "Spent Fuel Storage Pool Water Level."

ACTIONS

A.1

If the water level is $<$ 23 ft above the top of the irradiated fuel assemblies seated within the RPV, all operations involving movement of fuel assemblies and handling of control rods within the RPV shall be suspended Immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV, ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. This verification can be performed using the normal RPV water level indication, which is referenced to Top of Active Fuel (TAF). Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 1).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. UFSAR, Section 15.2.5.

2. Regulatory Guide 1.183.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Residual Heat Removal (RHR) — High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as described by UFSAR Section 3.1.2.4.5 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal after initial decay heat levels have decreased sufficiently. During the initial phases of cooldown, when decay heat levels are high, operation of both RHR System heat exchangers may be required (Ref. 2). MODE 5 is typically not entered until decay heat levels have fallen to levels that are within the capability of one RHR subsystem. In addition, procedures require the reactor coolant temperature to be maintained less than 150^0F before the RPV may be disassembled and the RPV water level increased to the range when this Specification is applicable. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the 'B' recirculation loop and Reactor Pressure Vessel (RPV) bottom head. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the recirculation loop and associated low pressure coolant injection path, or to the reactor via Spent Fuel Pool and Spent Fuel Pool Cooling return flow path. The RHR heat exchangers transfer heat to the RHR Service Water (RHRSW) System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the RPV flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

RHR – High Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level ≥ 21 ft-1 inch above the top of the RPV flange. A minimum water level of 21 ft-1 inch above the top of the RPV flange corresponds to a level of 36 ft in the Spent Fuel Pool (SFP). Therefore, SFP water level indication may be used to monitor RPV level when the RPV is flooded up and the SFP gates are removed. Other means of monitoring RPV water level are used when those conditions are not present. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability. In addition, when the reactor coolant temperature is ≥ 150°F, one RHR shutdown cooling subsystem is required to be in operation to provide an active decay heat removal capability. At reactor coolant temperatures less than 150°F, natural circulation alone is adequate to provide the required decay heat removal capability while maintaining adequate margin to the reactor coolant temperature (212°F) at which a MODE change would occur.
An OPERABLE RHR shutdown cooling subsystem consists of one RHR pump, a heat exchanger, an RHRSW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In addition, the necessary portions of the Emergency Service Water and River Water Supply System and Ultimate Heat Sink are required to provide appropriate cooling and a suction source to each required RHRSW pump.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring when the reactor coolant temperature is ≥ 150°F, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation during any 8 hour period. This 8 hour period is a continuous rolling clock. The 2 hour exception provides operational flexibility for varying plant conditions. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

(continued)

BASES (continued)

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level ≥ 21 ft-1 inch above the top of the RPV flange. In addition, one RHR shutdown cooling subsystem must be operating to provide decay heat removal when the reactor coolant temperature is ≥ 150°F. RHR System requirements in other MODES are covered by LCOs in Section 3.4, REACTOR COOLANT SYSTEM (RCS). RHR Shutdown Cooling System requirements in MODE 5 with irradiated fuel in the reactor pressure vessel and with the water level < 21 ft-1 inch above the top of the RPV flange are given in LCO 3.9.8, “RHR – Low Water Level.”

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be verified by administrative means within 1 hour. In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in operating procedures. Alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, Reactor Water Cleanup System, Reactor Cavity Floodup and Fuel Pool Cooling System return to the cavity.

(continued)

BASES

ACTIONS

A.1 (continued)

Heat losses to ambient surroundings may be included in the total capacity of the alternate heat removal methods employed to satisfy Required Action A.1. The alternate heat removal methods satisfy Required Action A.1 when the total alternate heat removal capacity exceeds the decay heat generation rate. The method used to remove the decay heat should be the most prudent choice based on unit conditions.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken Immediately to suspend operations involving an increase in reactor decay heat load by suspending loading of irradiated fuel assemblies into the RPV.

Additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability (i.e., one secondary containment isolation valve/damper and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If no RHR shutdown cooling is in operation when reactor coolant temperature is ≥ 150°F, except as permitted by the LCO Note, an alternate method of coolant circulation is required to be established within 1 hour. However, with the water level high, coolant circulation is assured by virtue of being flooded up to a level significantly higher than the minimum natural circulation level (i.e., lowest turnaround point for water in the steam separator) and thus, Required Action C.1 is met.

During the period of time when the reactor coolant is either being naturally circulated or circulated by another alternate method, the reactor coolant temperature must be periodically monitored to ensure proper circulation is maintained. The once per hour Completion Time is deemed appropriate due to the passive nature of the circulation process.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This Surveillance demonstrates that the RHR subsystem is in operation and circulating reactor coolant when reactor coolant temperature is ≥ 150°F.

The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability corresponding to the decay heat load that is present. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

SR 3.9.7.2

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling System locations susceptible to gas accumulation is based on a review of system design

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.2 (continued)

information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Shutdown Cooling System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Shutdown Cooling System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.2 (continued)

Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. UFSAR, Section 3.1.2.4.5.
2. UFSAR, Section 5.4.7.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR) — Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as described by UFSAR, Section 3.1.2.4.5 (Ref.1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal after initial decay heat levels have decreased sufficiently. During the initial phases of cooldown, when decay heat levels are high, operation of both RHR System heat exchangers may be required (Ref. 2). MODE 5 is typically not entered until decay heat levels have fallen to levels that are within the capability of one RHR subsystem. In addition, procedures require the reactor coolant temperature to be maintained less than 150°F before the RPV may be disassembled. Both loops have a common suction from the 'B' recirculation loop and Reactor Pressure Vessel (RPV) bottom head. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the recirculation loop and associated low pressure coolant injection path or to the reactor via the Spent Fuel Pool and Spent Fuel Pool Cooling return flow path. The RHR heat exchangers transfer heat to the RHR Service Water (RHRSW) System. The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

RHR – Low Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

In MODE 5 with irradiated fuel in the RPV and the water level < 21 ft-1 inch above the top of the RPV flange, two RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of one RHR pump, a heat exchanger, an RHRSW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. To meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. In addition, the necessary portions of the Emergency Service Water and River Water Supply Systems and the Ultimate Heat Sink are required to provide appropriate cooling and a suction source to each required RHRSW pump. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation during any 8 hour period. This 8 hour period is a continuously rolling clock. The 2 hour exception provides operational flexibility for varying plant conditions.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE, and one must be in operation in MODE 5, with irradiated fuel in the RPV and with the water level < 21 ft-1 inch above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, REACTOR COOLANT SYSTEM (RCS). RHR Shutdown Cooling System requirements in MODE 5 with irradiated fuel in the RPV and with the water level ≥ 21 ft-1 inch above the top of the RPV flange are given in LCO 3.9.7, "Residual Heat Removal (RHR) — High Water Level."

(continued)

BASES (continued)

ACTIONS

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore an alternate method of decay heat removal must be verified by administrative means. With both required RHR shutdown cooling subsystems inoperable, another alternate method of decay heat removal must be verified by administrative means in addition to that verified for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of this alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in operating procedures. Alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, feed and bleed to the torus via Safety Relief Valves, and Reactor Water Cleanup System. Heat losses to ambient surroundings may be included in the total capacity of the alternate heat removal methods employed to satisfy Required Action A.1. The alternate heat removal methods satisfy Required Action A.1 when the total alternate heat removal capacity exceeds the decay heat generation rate. The method used to remove decay heat should be the most prudent choice based on unit conditions.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability (i.e., one secondary containment isolation valve/damper and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR subsystem is in operation, except as permitted by the LCO Note, an alternate method of coolant circulation (e.g., natural circulation when the minimum natural circulation level is maintained, starting a recirculation pump or RWCU in service) is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each subsequent loss of either forced or natural circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This Surveillance demonstrates that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability corresponding to the decay heat load that is present.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystems in the control room.

SR 3.9.8.2

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walkdowns to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as standby versus operating conditions.

The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR Shutdown Cooling System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.8.2 (continued)

met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Shutdown Cooling System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. UFSAR, Section 3.1.2.4.5.
2. UFSAR, Section 5.4.7.2.2.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 System Leakage and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the Reactor Pressure Vessel (RPV) require the pressure testing at temperatures > 212°F (normally corresponding to MODE 3) or to allow completing these reactor pressure tests when the initial conditions do not require temperatures > 212ºF. Futhermore, the purpose is to allow continued performance of control rod scram time testing required by SR 3.1.4.1 or SR 3.1.4.2 if reactor coolant temperatures exceed 212ºF when the control rod scram time testing is initiated in conjunction with a system leakage or hydrostatic test. These control rod scram times tests would be performed in accordance with LCO 3.10.4, “Single Control Rod Withdrawal – Cold Shutdown,” during MODE 4 operation.

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. In addition, a hydrostatic test pump or a control rod drive pump may be used to achieve required test pressure. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing may eventually be required with minimum reactor coolant temperatures > 212°F. However, even with required

(continued)

BASES

BACKGROUND (continued)

minimum reactor coolant temperatures ≤ 212ºF, maintaining RCS temperatures within a small band during the test can be impractical. Removal of heat addition from recirculation pump operation and reactor core decay heat is coarsely controlled by control rod drive hydraulic system flow and reactor water cleanup system non-regenerative heat exchanger operation. Test conditions are focused on maintaining a steady state pressure, and tightly limited temperature control poses an unnecessary burden on the operator and may not be achievable in certain instances.

At the DAEC, the hydrostatic testing required by Reference 1 is implemented using the allowances provided by Code Case N-498 (Ref. 2). This Code Case allows testing to be performed at the nominal operating pressure of 1025 psig. The system leakage testing is also performed at also performed at the nominal operating pressure as allowed by Reference 1. Scram time testing required by SR 3.1.4.1 and 3.1.4.2 requires reactor pressure ≥ 800 psig.

Other testing may be performed in conjunction with the allowances for system leakage or hydrostatic tests and control rod scram time tests.

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4 when the reactor coolant temperature is > 212°F, during, or as a consequence of, hydrostatic or leak testing, or as a consequence of control rod scram time testing initiated in conjunction with a system leakage or hydrostatic test, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.4.6, "RCS Specific Activity," limits are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 3. Therefore,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

these requirements will conservatively limit radiation releases to the environment.

In the unlikely event of any primary system leak that could result in draining the RPV, the reactor vessel would rapidly depressurize. The makeup capability required in MODE 4 by LCO 3.5.2, "RPV Water Inventory Control," would be more than adequate to keep the RPV water level above the TS 2.1.1.3 Safety Limit under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures $>$ 212°F can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures $>$ 212°F, while some system leakage or hydrostatic testing may require the safety/relief valves to be gagged, preventing their OPERABILITY. Additionally, even with required minimum reactor coolant temperature ≤ 212ºF, RCS temperatures may drift above 212ºF during the performance of system leakage and hydrostatic testing or during subsequent control rod scram time testing, which is typically performed in conjunction with a system leakage or hydrostatic test. While this Special Operations LCO is provided for system leakage and hydrostatic testing, and for scram time testing initiated in conjunction with a system leakage or

(continued)

BASES

LCO (continued)

hydrostatic test, parallel performance of other tests and inspections is not precluded.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System — Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures $>$ 212°F for the purpose of performing a system leakage or hydrostatic test, and for control rod scram time testing initiated in conjunction with a system leakage or hydrostatic test.

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements.

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of, or as a consequence of, system leakage or hydrostatic tests, or as a consequence of control rod scram time testing initiated in conjunction with a system leakage or hydrostatic test, so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is $>$ 212°F. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A Note has been provided to modify the ACTIONS related to system leakage and hydrostatic testing operation. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO

(continued)

BASES

ACTIONS (continued)

not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements are entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to $\leq$ 212°F.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operation LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to $\leq$ 212°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 to reach MODE 4 from MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

(continued)

BASES (continued)

REFERENCES

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, Edition and Addenda as Referenced in the Current Inservice Inspection Program.

2. Code Case N-498 (latest approved revision), Alternative Rules for 10 Year System Hydrostatic Testing for Class 1, 2 and 3 Systems, Section XI, Division 1.

3. UFSAR, Section 15.2.1.5.

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown — Initiates a reactor scram; bypasses main steam line isolation scram;

b. Refuel — Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation scram;

c. Startup/Hot Standby — Selects NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation scram; and

d. Run — Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, and main steam isolation valve isolations.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality. The interlock functions of the Shutdown and Refuel positions normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (Run, Startup/Hot Standby, or Refuel) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies, and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Refs. 2 and 3). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod Withdrawal — Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal — Cold Shutdown," and LCO 3.10.8, "SDM Test — Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can

(continued)

BASES

LCO (continued)

be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in Shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5, with the reactor mode switch in other than the Shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

In MODE 5, with the reactor mode switch in the Refuel position, only one control rod can be withdrawn under the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks, and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed without this allowance or testing that must be performed prior to entering another MODE. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in Shutdown (i.e., all control rods inserted and incapable of withdrawal) and Refuel (i.e., refueling

(continued)

BASES

APPLICABILITY (continued)

interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS, except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore, do not have to be inserted. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the Shutdown position will ensure that all inserted control rods remain inserted and result in operating in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the Refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the Shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Action A.2, Required Action A.3.1, and Required Action A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the Shutdown position (or the Refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillances are intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

REFERENCES

1. UFSAR, Section 7.2.1.1.6.

2. UFSAR, Section 15.1.4.3.

3. UFSAR, Section 15.1.4.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal — Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in Hot Shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the Shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the other installed interlocks that are actuated when the reactor mode switch is in the Shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the Refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the Refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of an accident. Explicit safety analyses in the UFSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the Refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing," without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn.

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

(continued)

BASES (continued)

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the Refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication"), full insertion requirements for all other control rods and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," and LCO 3.9.5," Control Rod OPERABILITY — Refueling"), or the added administrative controls in Item d.2 of this Special Operations LCO, minimize potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action to insert all control rods.

(continued)

BASES

ACTIONS

A.1 (continued)

This Required Action includes exiting this Special Operations Applicability by returning the reactor mode switch to the Shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the Shutdown position will ensure all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the Shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued)

It is preferred to electrically disarm the control rods since, in this case, drive water cools and minimizes crud accumulation in the drive. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable because of the administrative controls on control rod withdrawal, the protection afforded by the LCOs involved, and hard-wired interlocks that preclude additional control rod withdrawals.

REFERENCES

1. UFSAR, Section 15.1.4.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal — Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in Cold Shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the Shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the Shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated Control Rod Drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the Refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the Refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of an accident. Explicit safety analyses in the UFSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing a CRD because this removal renders the withdrawn control rod incapable of being scrammed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the Refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or when the CRD is to be

(continued)

BASES

LCO (continued)

removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the Refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," and LCO 3.9.5, "Control Rod OPERABILITY — Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS (continued)

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations Applicability by returning the reactor mode switch to the Shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the Shutdown position. Actions must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the Shutdown position provides sufficient time to normally insert the control rods.

B.1, B.2.1, and B.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must be immediately suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. It is preferred to electrically disarm the control rods since, in this condition, drive water cools and minimizes crud accumulation in the drive. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hard-wired interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. UFSAR, Section 15.1.4.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal — Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures, and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY — Refueling").

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the Refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of accidents. Explicit safety analyses in the UFSAR (Ref. 1) demonstrate that proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn (by insertion of a control rod block).

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES (continued)

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs, LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented, and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduce the potential for reactivity excursions.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods, other than the control rod withdrawn for removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. It is preferred to electrically disarm the control rods since, in this condition, drive water cools and minimizes crud accumulation in the drive. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5 (continued)

is required to ensure the assumptions of the safety analysis are satisfied. Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable, given the administrative controls on control rod removal and hard-wired interlocks to block an additional control rod withdrawal.

REFERENCES

1. UFSAR, Section 15.1.4.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal — Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rod may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypassing the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the UFSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated Control Rod Drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from the cell. With no fuel assemblies in the core cell, the associated

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with either LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY — Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

When fuel is loaded into the core with multiple control rods withdrawn, reload sequences are used to ensure that reactivity additions are minimized.

(continued)

BASES (continued)

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.

REFERENCES

1. UFSAR, Section 15.1.4.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.7 Control Rod Testing — Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the Rod Worth Minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the Low Power Setpoint (LPSP) of the RWM. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a Control Rod Drop Accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests include SDM demonstrations, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exemption to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analysis of References 1 and 2 may not be preserved. Therefore special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.7 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator or other qualified member of the technical staff. These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."

APPLICABILITY

Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than the LPSP of the RWM, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR), and LCO 3.3.2.1. With THERMAL POWER less than or equal to the LPSP of the RWM, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6.

(continued)

BASES

APPLICABILITY (continued)

While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal — Hot Shutdown," or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal — Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 1 and 2 are satisfied. During these Special Operations and while in MODE 5, the one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock,") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY — Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, provide mitigation of potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence, the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

With the special test sequence not programmed into the RWM, a second licensed operator or other qualified member of the technical staff (i.e., a person trained in accordance with an approved training program for this test) is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be performed if SR 3.10.7.2 is satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.7.2

When the RWM provides conformance to the special test sequence, the test sequence must be verified to be correctly loaded into the RWM prior to control rod movement. This Surveillance demonstrates compliance with SR 3.3.2.1.7, thereby demonstrating that the RWM is OPERABLE. A Note has been added to indicate that this Surveillance does not need to be performed if SR 3.10.7.1 is satisfied.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).

2. Letter from T. Pickens (BWROG) to G.C. Lainas (NRC) "Revision 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test — Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the Reactor Pressure Vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following the refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5, with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the Shutdown or Refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the Startup/Hot Standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the Startup/Hot Standby position while in MODE 5, is provided by the Intermediate Range Monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"). The limiting reactivity excursion event during control rod withdrawal while in MODE 5 is the Control Rod Drop Accident (CRDA).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the RWM, APRM, and control rod coupling, the notch out mode is specified for out of sequence withdrawals. Requiring the notch out mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2.a and 2.d) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, RPS MODE 2 requirements for Functions 2.a and 2.d of Table 3.3.1.1-1 must be enforced and the approved control rod withdrawal

(continued)

BASES

LCO (continued)

sequence must be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2), or must be verified by a second licensed operator or other qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in LCO 3.1.6, "Rod Pattern Control," (i.e., out of sequence control rod withdrawals) must be made in the individual notched withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the Startup/Hot Standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1 and A.2

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since, if the control rod fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

in the Shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," Actions provide additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the Shutdown or Refuel position. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown or Refuel position is permitted by the definition of an Immediate Completion Time. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a and 2.d, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed any time a control rod is withdrawn to the "full out" notch position, or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 970 psig is well below the expected pressure of 1100 psig. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).

2. Letter from T. Pickens (BWROG) to G.C. Lainas, NRC, "Revision 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.