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December 12, 2007
GO2-07-175

10 CFR 50.71(e)
10 CFR 50.4

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

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397,
10 CFR 50.71 MAINTENANCE OF RECORDS
LICENSING BASIS DOCUMENT UPDATE**

Dear Sir or Madam:

In accordance with the requirements of 10 CFR 50.71(e) and 10 CFR 50.4, Energy Northwest hereby submits the updated Columbia Generating Station (Columbia):

- Final Safety Analysis Report (FSAR), Amendment 59;
- Technical Specification (TS) Bases, Revision 52;
- Licensee Controlled Specifications (LCS), Revision 52; and
- Operational Quality Assurance Program Description (OQAPD), Revisions 41 and 42.

In addition to other changes, Amendment 59 removes some redundant information and excessive detail from the FSAR to improve its focus and clarity. In accordance with Regulatory Guide 1.181, a brief description of the information removed is provided in Attachment 1.

Energy Northwest is submitting the FSAR on CD-ROM (Enclosure 1). Based on the guidance summarized in the NRC Regulatory Issue Summary 2005-26, "Control of Sensitive Unclassified Nonsafeguards Information Related to Nuclear Power Reactors," dated November 7, 2005, Energy Northwest believes that the FSAR contains some information that should not be made publicly available. Therefore, the submittal contains a separate copy of the FSAR CD-ROM that contains only the files that can be made publicly available (Enclosure 2). The CD-ROM labeled, "Columbia Generating Station FSAR, Amendment 59 - Non-publicly Available - Withhold under 10 CFR 2.390" contains sensitive, unclassified (nonsafeguards) information and Energy Northwest requests that the files contained on this CD be withheld from public disclosure, in accordance with 10 CFR 2.390(d)(1).

The files on the CDs are in the Portable Document Format (PDF). This submittal contains PDF files, one or more of which contains hyperlinks to other files or to the Internet. These hyperlinks are either inoperable or are not essential to the use of the

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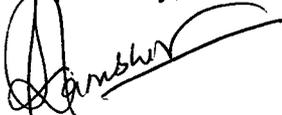
filing. Any material referenced by hyperlinks to the Internet that was essential for use of this filing has been submitted as part of the filing. Any material referenced by a hyperlink to another PDF that was essential for the use of this filing has either been included by reference or submitted as part of this filing. For instructions to access the FSAR using Adobe Reader, open the "ReadMe.pdf" file on the CD-ROM. The NRC "Guidance for Electronic Submissions to the Commission" (as referenced in 10 CFR 50.4(b)(6)) recommends that the submittal describe document components such as file name, size, and sensitivity level. Attachment 2 provides that information for both versions of the FSAR.

Should you need additional information, please contact:

Name	Don Gregoire
Mailing Address	Acting, Licensing Supervisor Energy Northwest P.O. Box 968, Mail Drop PE20 Richland, Washington 99352
E-Mail Address	dwgregoire@energy-northwest.com
Phone Number	(509) 377-8616

I declare under penalty of perjury that the foregoing is true and correct. Executed on the date of this letter.

Respectfully,



SK Gambhir
Vice President, Technical Services

- Enclosures:
1. CD-ROM labeled, "Columbia Generating Station FSAR, Amendment 59 - Non-publicly Available – Withhold under 10 CFR 2.390" (Withhold from Public Disclosure)
 2. CD-ROM labeled, "Columbia Generating Station FSAR, Amendment 59 - Publicly Available"
 3. Technical Specification Bases, Revision 52
 4. Licensee Controlled Specifications, Revision 52
 5. Operational Quality Assurance Program Description, Revisions 41 and 42

- Attachments:
1. Redundant Information and Excessive Detail Removed from the FSAR
 2. Document Components

cc: EE Collins, Jr. – NRC RIV WA Horin – Winston & Strawn (w/o)
CF Lyon – NRC NRR (w/o) RN Sherman – BPA/1399 (w/o)
NRC Sr. Resident Inspector/988C (TS Bases, LCS, and OQAPD, sent previously)

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Attachment 1

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Redundant Information and Excessive Detail Removed from the FSAR

CHAPTER 1

No deleted information

CHAPTER 2		
Section	Description of Change	Type
2.3.4	Removed excessive detail describing PAVAN code calculation of X/Q.	Excessive detail
2.3.4	Deleted second call out of the Regulatory Guide title.	Redundant information
Table 2.3-33a	Deleted data from table that was not used in any plant analyses.	Excessive detail
Table 2.3-34a	Deleted data from table that was not used in any plant analyses.	Excessive detail

CHAPTER 3		
Section	Description of Change	Type
Table 3.2-1	Deleted the listing of refueling equipment and tools from the list of seismic and quality class for systems.	Excessive detail
Table 3.9-2b	Removed note to reference.	Redundant information

CHAPTER 4

No deleted information

CHAPTER 5		
Section	Description of Change	Type
5.4.6.1	Deleted redundant information concerning HPCS and ADS from the RCIC discussion.	Redundant information
5.4.6.2.1.1	Removed excessive detail from discussion of RCIC pump vortexing.	Excessive detail

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Attachment 1

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CHAPTER 6		
Section	Description of Change	Type
6.2.3.2	Deleted pressure details that are provided in other locations.	Redundant information
6.2.3.2	Removed list of bypass valves and lines that is redundant to table information.	Redundant information
6.2.3.3	Replaced discussion of secondary containment response with the new analysis, with less detail.	Excessive detail
6.2.3.4	Deleted calculation details.	Excessive detail
6.3.2.2	Deleted details regarding specifics for ECCS NPSH and reference general discussion in Section 6.3.2.2.6.	Excessive detail
6.3.2.2.6	Deleted details concerning parameters used to specify ECCS suction strainers.	Excessive detail
6.5.1.2	Revised the description of the SGT system design. The revised discussion removed redundant information and deleted excessive detail.	Redundant information and excessive detail
6.5.1.3	Deleted redundant information found in previous section.	Redundant information
Table 6.2-16	Deleted redundant information in note 24 that is adequately covered in the text.	Redundant information
Table 6.2-29	Deleted table with obsolete information, but did not replace it because redundant information was provided graphically.	Redundant information

CHAPTER 7
No deleted information

CHAPTER 8
No deleted information

CHAPTER 9		
Section	Description of Change	Type
9.1.4.2.2.10	Deleted the material for the fuel shipping outer container.	Excessive detail
9.1.4.2.2.10	Deleted repetitive discussion of equipment used to move fuel.	Redundant information
9.1.4.2.2.10	Deleted details for new fuel inspection.	Excessive detail
Table 9.5-2	Deleted the listing of portable lighting since more detailed information is provided in other locations.	Redundant information

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Attachment 1
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CHAPTER 10
No deleted information

CHAPTER 11		
Section	Description of Change	Type
11.5.2.1	Deleted discussion that content of the FSAR was accepted in the NRC SER and was part of an Operating License Condition.	Excessive detail

CHAPTER 12		
Section	Description of Change	Type
Figure 12.5-1	Deleted the floor plan figure of the Kootenai Building.	Excessive detail

CHAPTER 13		
Section	Description of Change	Type
13.1.1	Deleted discussion of roles and responsibilities for the Corrective Action Manager or Supervisor because this is covered in the OQAPD.	Excessive detail

CHAPTER 14
No deleted information

CHAPTER 15		
Section	Description of Change	Type
15.2.1.3	Deleted this section because it was redundant to the information in 15.2.1.3.3.	Redundant information
15.2.3.3.1.2	Deleted details of mathematical model that are included in another section (15.0.3.3.1).	Redundant information
15.2.4.3.3.1	Removed redundant information from this section that was provided in Tables 15.0-1 and 15.2-6 and Figure 15.2-5.	Redundant information
15.2.4.4.2	Deleted "unacceptably" as a qualifier for high power level.	Excessive detail
15.2.5.2.3	Deleted discussion about the event that was adequately discussed in another section.	Redundant information
15.2.7.2	Removed specific times from text that are contained in the sequence of events table.	Redundant information
15.3.1.5	Deleted information describing the event that is redundant to the previous paragraph.	Redundant information

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CHAPTER 15		
Section	Description of Change	Type
15.4.9.2	Deleted redundant information and excessive detail regarding system operations.	Redundant information and excessive detail

CHAPTERS 16 and 17
No deleted information

APPENDIX B
No deleted information

APPENDIX F		
Section	Description of Change	Type
Table F.4-1	Deleted the list of auxiliary equipment. The supported equipment is adequately addressed.	Excessive detail

APPENDIX I and J
No deleted information

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Attachment 2

Page 1 of 2

Document Components FSAR Amendment 59 Non-Publicly Available		
File Name	Size (bytes)	Availability
ReadMe.pdf	27,049	Non-publicly Available
Index.pdx	475	Non-publicly Available
index1.idx	10,193,221	Non-publicly Available
index.idx	4,848	Non-publicly Available
001General TOC.pdf	51,646	Non-publicly Available
002 List of Effective Pages.pdf	155,196	Non-publicly Available
003 Chapter 1.pdf	42,593,577	Non-publicly Available
004 Chapter 2.pdf	17,902,472	Non-publicly Available
005 Chapter 3 page 3-i to Figure 3.5-15.pdf	37,371,588	Non-publicly Available
006 Chapter 3 Figure 3.5-16 to Figure 3.6-5.pdf	29,278,348	Non-publicly Available
007 Chapter 3 Figure 3.6-6 to Figure 3.12-4.pdf	42,465,823	Non-publicly Available
008 Chapter 3a.pdf	16,308,492	Non-publicly Available
009 Chapter 4.pdf	3,657,391	Non-publicly Available
010 Chapter 5.pdf	15,718,644	Non-publicly Available
011 Chapter 6.pdf	4,453,904	Non-publicly Available
012 Chapter 7.pdf	21,692,722	Non-publicly Available
013 Chapter 8.pdf	28,449,915	Non-publicly Available
014 Chapter 9.pdf	41,192,393	Non-publicly Available
015 Chapter 10.pdf	15,606,077	Non-publicly Available
016 Chapter 11.pdf	5,581,926	Non-publicly Available
017 Chapter 12.pdf	39,308,497	Non-publicly Available
018 Chapter 13.pdf	425,285	Non-publicly Available
019 Chapter 14.pdf	745,865	Non-publicly Available
020 Chapter 15.pdf	4,529,829	Non-publicly Available
021 Chapter 16.pdf	37,503	Non-publicly Available
022 Chapter 17.pdf	420,024	Non-publicly Available
023 Appendix B.pdf	472,033	Non-publicly Available
024 Appendix F.pdf	9,363,906	Non-publicly Available
025 Appendix I.pdf	405,138	Non-publicly Available
026 Appendix J.pdf	3,793,244	Non-publicly Available

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Attachment 2

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Document Components FSAR Amendment 59 Publicly Available		
File Name	Size (bytes)	Availability
ReadMe.pdf	27,049	Publicly Available
Index.pdx	480	Publicly Available
index1.idx	9,899,199	Publicly Available
index.idx	4,848	Publicly Available
001 General TOC.pdf	51,646	Publicly Available
002 List of Effective Pages.pdf	155,196	Publicly Available
003 Chapter 1.pdf	2,077,697	Publicly Available
004 Chapter 2.pdf	4,146,949	Publicly Available
005 Chapter 3 page 3-i to Figure 3.5-15.pdf	34,410,847	Publicly Available
006 Chapter 3 Figure 3.5-16 to Figure 3.6-5.pdf	3,480,144	Publicly Available
007 Chapter 3 Figure 3.6-6 to Figure 3.12-4.pdf	4,889,304	Publicly Available
008 Chapter 3a.pdf	15,822,219	Publicly Available
009 Chapter 4.pdf	3,619,032	Publicly Available
010 Chapter 5.pdf	15,453,221	Publicly Available
011 Chapter 6.pdf	4,442,560	Publicly Available
012 Chapter 7.pdf	21,692,722	Publicly Available
013 Chapter 8.pdf	4,616,128	Publicly Available
014 Chapter 9.pdf	29,951,998	Publicly Available
015 Chapter 10.pdf	15,606,077	Publicly Available
016 Chapter 11.pdf	5,581,926	Publicly Available
017 Chapter 12.pdf	1,029,254	Publicly Available
018 Chapter 13.pdf	425,285	Publicly Available
019 Chapter 14.pdf	745,865	Publicly Available
020 Chapter 15.pdf	4,529,829	Publicly Available
021 Chapter 16.pdf	37,503	Publicly Available
022 Chapter 17.pdf	420,024	Publicly Available
023 Appendix B.pdf	472,033	Publicly Available
024 Appendix F.pdf	1,624,501	Publicly Available
025 Appendix I.pdf	405,138	Publicly Available
026 Appendix J.pdf	1,124,767	Publicly Available

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Enclosure 3

**COLUMBIA GENERATING STATION
TECHNICAL SPECIFICATIONS BASES
INSERTING INSTRUCTIONS**

The following instruction is to assist you in replacing your old copy of Energy Northwest's Columbia Generating Station Technical Specifications Bases.

This copy includes revisions 41 through 52

If you have any questions concerning insertion of this revision, or if you are missing any pages, please contact Lori Walli (509) 377-4149.

Discard
Old Page

All Pages*

Insert
New Page

All Pages

* Do not discard divider tabs

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B 3.10.5	Single Control Rod Drive (CRD) Removal—Refueling	B 3.10.5-1
B 3.10.6	Multiple Control Rod Withdrawal—Refueling	B 3.10.6-1
B 3.10.7	Control Rod Testing—Operating	B 3.10.7-1
B 3.10.8	SHUTDOWN MARGIN (SDM) Test—Refueling	B 3.10.8-1

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (A00s).

The fuel cladding integrity SL is set such that no 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 A00s, 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 Emergency Core Cooling System initiation setpoints higher than this safety limit provides margin such that the safety limit will not be reached or exceeded.

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The fuel cladding must not sustain damage as a result of normal operation and AOOs. 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 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

The SPCB critical power correlation is used for the Framatome ANP and Westinghouse SVEA-96 fuel. The use of the correlation for the Framatome ANP fuel is valid for critical power calculations at pressures ≥ 571.4 psia and ≤ 1432 psia and bundle mass fluxes $\geq 0.087 \times 10^6$ lbm/hr-ft² and $\leq 1.5 \times 10^6$ lbm/hr-ft² (Reference 2). Application of the SPCB critical power correlation to the Westinghouse SVEA-96 fuel was established using the methodology presented in Reference 3. The correlation for the SVEA-96 fuel is valid

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BASES

APPLICABLE
SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

for critical power calculations at pressures ≥ 576 psia and ≤ 1261 psia and bundle mass fluxes $\geq 0.21 \times 10^6$ lbm/hr-ft² and $\leq 1.61 \times 10^6$ lbm/hr-ft² (Reference 4). For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis: Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ensure a minimum bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. The minimum bundle flow is $> 28 \times 10^3$ lb/hr. The coolant minimum bundle flow and maximum flow area are such that the mass flux is $> 0.25 \times 10^6$ lb/hr-ft². Full scale critical power tests taken at pressures down to 14.7 psia indicate that the fuel assembly critical power at 0.25×10^6 lb/hr-ft² is approximately 3.35 MWt. At 25% RTP, a bundle power of approximately 3.35 MWt corresponds to a bundle radial peaking factor of > 2.9 , which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 25% RTP for reactor pressures < 785 psig is conservative.

2.1.1.2 MCPR

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty inherent in the critical power correlation. References 2, 3, and 5 describe the uncertainties and methodology used in determining the MCPR SL.

The critical power correlations are based on a significant body of practical test data, providing a high degree of assurance that the critical power, as evaluated by the

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BASES

APPLICABLE
SAFETY ANALYSES

2.1.1.2 MCPR (continued)

correlation, is within a small percentage of the actual critical power. As long as the core pressure and flow are within the range of validity of the critical power correlations, the assumed reactor conditions used in defining the SL introduce conservatism into the limit by using conservative radial and local power distributions to estimate the number of rods in boiling transition. This conservatism and the inherent accuracy of the critical power correlations provide a reasonable degree of assurance that there would be no transition boiling in the core during sustained operation at the MCPR SL. If boiling transition were to occur, there is reason to believe that the integrity of the fuel would not be compromised. Significant test data accumulated by the NRC and private organizations indicate that the use of a boiling transition limitation to protect against cladding failure is a very conservative approach. Much of the data indicate that BWR fuel can survive for an extended period of time in an environment of boiling transition.

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 irradiated 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 has been established at the top of the active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to prevent the release of radioactive materials to the environs. SL 2.1.1.1 and

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BASES

SAFETY LIMITS (continued) 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 limits (Ref. 6). Therefore, it is required to 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 the probability of an accident occurring during this period is minimal.

- REFERENCES
1. 10 CFR 50, Appendix A, GDC 10.
 2. EMF-2209(P)(A) Revision 2, "SPCB Critical Power Correlation," Framatome - ANP, September 2003.
 3. EMF-2245(P)(A) Revision 0, "Application of Siemens Power Corporation's Critical Power Correlation to Co-resident Fuel," Siemens Power Corporation, August 2000.
 4. NE-02-02-15 Revision 0, "Computation of SPCB Critical Power Correlation Additive Constants for SVEA-96," November 2002.
 5. ANF-524(P)(A) Revision 2 and Supplements 1 and 2, "ANF Critical Power Methodology for Boiling Water Reactors," Advanced Nuclear Fuels, November 1990.
 6. 10 CFR 50.67, "Accident Source Term."
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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 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 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 anticipated operational occurrences (AOOs).

During normal operation and AOOs, 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, "Inservice Leak and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of ASME Code, Section XI (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 (Ref. 4). If this occurred in conjunction with a fuel cladding failure, the number of protective barriers designed to prevent radioactive releases from exceeding the limits would be reduced.

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.

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

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 reactor pressure vessel is designed to ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition, including Addenda through the summer of 1971 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The SL of 1325 psig, as measured in the reactor steam dome, is equivalent to 1375 psig at the lowest elevation of the RCS. The RCS is designed to ASME Code, Section III, 1971 Edition, including Addenda through the summer of 1971 (Ref. 5), for the reactor recirculation piping, which permits a maximum pressure transient of 125% of design pressures of 1250 psig for suction piping and 1550 psig for discharge piping. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.

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 125% of design pressures of 1250 psig for suction piping and 1550 psig for discharge piping. The most limiting of these allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1325 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT
VIOLATIONS

Exceeding the RCS pressure SL may cause RCS failure and create a potential for radioactive releases in excess of 10 CFR 50.67 limits (Ref. 4). Therefore, it is required to 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 the probability of an accident occurring during this period is minimal.

(continued)

BASES (continued)

- REFERENCES
1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and GDC 28.
 2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
 3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IW-5000.
 4. 10 CFR 50.67, "Accident Source Term."
 5. ASME, Boiler and Pressure Vessel Code, 1971 Edition, Addenda, summer of 1971.
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B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs LCO 3.0.1 through LCO 3.0.8 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

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BASES

LCO 3.0.2
(continued)

ACTIONS.) The second type of Required Action 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 3.4.11, "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. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time other conditions exist which 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.

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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 3.7.7, "Spent Fuel Pool Water Level." LCO 3.7.7 has an Applicability of "During movement of irradiated fuel

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BASES

LCO 3.0.3
(continued)

assemblies in the associated fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.7 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 3.7.7 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 (i.e., 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 Action.

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.

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BASES

LCO 3.0.4
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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 10 CFR 50.65(a)(4), which requires risk impacts of maintenance activities to 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 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "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.

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BASES

LCO 3.0.4
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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 and 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 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 system 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., RCS 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

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BASES

LCO 3.0.4
(continued)

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, 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.

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 SRs to demonstrate:

- a. The OPERABILITY of the equipment being returned to service; or
- b. The OPERABILITY of other equipment.

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BASES

LCO 3.0.5
(continued)

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 allowed SRs. 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 SRs.

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 an SR 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 an SR on another channel in the same trip system.

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's 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's 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

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BASES

LCO 3.0.6
(continued)

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' LCO's 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 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. 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 (continued)

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 be changed to perform the special test or operation will remain in effect.

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

(continued)

BASES

LCO 3.0.8
(continued)

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 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.

LCO 3.0.8 only applies to snubber support functions that are seismic related. In MODES 4 and 5, snubbers only perform seismic support functions. In MODES 1, 2, and 3, some snubbers inside the drywell and in the Turbine Building also perform non-seismic support functions (e.g., hydrodynamic loads, turbine trip loads, etc.). These snubbers are normally inaccessible in MODES 1, 2, and 3.

For snubbers that are being addressed in accordance with this LCO, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), the implementation of any applicable restrictions, and the associated plant configuration must all be available on a recoverable basis for NRC inspection.

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.

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BASES

LCO 3.0.8
(continued)

When LCO 3.0.8.a is used, one of the following two means of heat removal must be available:

- At least one high-pressure makeup path (i.e., using high-pressure core spray or reactor core isolation cooling) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or
- At least one low-pressure makeup path (e.g., low-pressure coolant injection or core spray) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).

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.

When LCO 3.0.8.b is used, it must be verified that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate LOOP accident sequences.

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.

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.

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 and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 800 psi to perform other necessary testing.
- b. Reactor Core Isolation Cooling (RCIC) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with RCIC 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 the 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 limits of the specified Frequency, whichever is greater, applies from the point in time 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. This delay period provides adequate time to complete Surveillances that

(continued)

BASES

SR 3.0.3
(continued)

have been missed. This delay period permits the completion of a Surveillance, or allows time to obtain a temporary waiver of the Surveillance Requirement (Ref.1), 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 Surveillances as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning,

(continued)

BASES

SR 3.0.3
(continued)

availability of 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 1.182, 'Assessing and Managing Risk Before Maintenance Activities 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 source of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then 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.

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BASES (continued)

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. 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.

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BASES

SR 3.0.4
(continued)

The provisions of SR 3.0.4 shall not prevent entry into 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, MODE 2 to MODE 3, and MODE 3 to MODE 4.

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.

REFERENCES

1. NRC Generic Letter 87-09, "Sections 3.0 and 4.0 of the Standard Technical Specifications (STS) on the Applicability of Limiting Conditions for Operation and Surveillance Requirements."
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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 Events;
- 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 GDC 26 (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE
SAFETY ANALYSES

Having sufficient SDM assures that the reactor will become and remain subcritical after all design basis accidents and transients. For example, SDM is assumed as an initial condition for the control rod removal error during a refueling accident (Ref. 2). The analysis of this reactivity insertion event 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.

SDM satisfies Criterion 2 of Reference 3.

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BASES (continued)

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, a design margin is included to account for uncertainties in the design calculations (Ref. 4).

APPLICABILITY In MODES 1 and 2, SDM must be provided to assure shutdown capability. 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 inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies (Ref. 2).

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 6 hour Completion time is acceptable, considering that the reactor can still be shut down, assuming no additional failures of 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 within 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.

(continued)

BASES

ACTIONS
(continued)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 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 results in the least reactive condition for the core. Actions 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 (SGT) subsystem is OPERABLE; and secondary containment isolation capability is available in 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 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 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). This may be performed as 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 SGT subsystem is OPERABLE; and secondary containment isolation capability is available in 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 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 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). This may be performed as 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.

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BASES (continued)

SURVEILLANCE
REQUIREMENTSSR 3.1.1.1

Adequate SDM must be verified to ensure 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 by testing before or during the first startup after fuel movement or 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 increased by an adder, "R", which is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated BOC core reactivity. If the value of R is negative (i.e., BOC is the most reactive point in the cycle), no correction to the BOC measured value is required. For the SDM demonstrations 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 demonstrated 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 LCO 3.10.7, "Control Rod Testing—Operating").

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and 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 also required to ensure the reactor does not reach criticality during control rod

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.1.1.1 (continued)

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. This evaluation ensures the intermediate loading patterns are bounded by the safety analyses for the final core loading pattern. For example, bounding analyses that demonstrate adequate SDM for the most reactive configurations during the refueling may be performed to demonstrate acceptability of the entire fuel movement sequence. These bounding analyses include additional margins to the associated uncertainties. Spiral offload or 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. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR, Section 15.4.1.1.
 3. 10 CFR 50.36(c)(2)(ii).
 4. FSAR, Section 4.3.2.4.1.
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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with GDC 26, GDC 28, and GDC 29 (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 anticipated operational occurrences. Reactivity Anomalies is used as a measure of the predicted versus measured 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, 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 ensuring 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,

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BASES

BACKGROUND
(continued)

the excess positive reactivity is compensated by burnable absorbers (e.g., gadolinia), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel.

The predicted core reactivity, as represented by 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 k_{eff} is calculated by the core monitoring system for actual plant conditions and is then compared to the predicted value for the 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 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 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 k_{eff} from the predicted 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 Reference 3.

(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 core k_{eff} and the predicted core k_{eff} of 1% $\Delta k/k$ 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, control rod 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 Anomalies 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 reviews the core conditions to determine their consistency with input to design calculations. Measured core and process parameters.

(continued)

BASES

ACTIONS

A.1 (continued)

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 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% $\Delta k/k$ 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 further assurance that plant operation is maintained within the assumptions of the DBA and transient analyses. The core monitoring system 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 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.2.1 (continued)

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} values 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. 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. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.
 2. FSAR, Chapters 15 and 15.F.
 3. 10 CFR 50.36(c)(2)(ii).
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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 that under conditions of normal operation, including anticipated operational occurrences, 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 of GDC 26, GDC 27, GDC 28, and GDC 29, (Ref. 1).

The CRD System consists of 185 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, 4, 5, and 6.

APPLICABLE
SAFETY ANALYSES

The analytical methods and assumptions used in the evaluations involving control rods are presented in References 2, 3, 4, 5, and 6. 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.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The capability of inserting the control rods provides 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 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 that 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)"), the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), 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. 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 Reference 7.

LCO

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 and therefore an inoperable accumulator does not immediately require declaring a control rod inoperable. Although not all control rods are required to be OPERABLE to

(continued)

BASES

LCO
(continued)

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 that allows the 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 stuck control rod separation criteria are met if: a) the stuck control rod is separated in all directions from each "slow" control rod by any combination of two or more fully inserted control rods or OPERABLE; withdrawn control rods that are not "slow"; and b) two or

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

less inoperable or "slow" control rods are in the same group as the stuck control rod. 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 within 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 amount of 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 should be isolated from scram by isolating the hydraulic control unit from scram and normal insert and withdraw pressure, while maintaining cooling water to the CRD.

Monitoring of the insertion capability for 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 and SR 3.1.3.3 perform 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 provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

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 have failed to insert when required. Therefore, the original SDM demonstration may not

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

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. 8).

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, C.2, and C.3

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the overall scram reactivity rate is met. To ensure the overall scram reactivity rate is met, the total number of "slow" and inoperable control rods must be immediately verified to be \leq eight. This ensures that the safety analysis assumptions are met (the safety analysis assumes a total of eight control rods are "slow," one is stuck, and another fails to scram. Therefore, ensuring the total number of "slow" and inoperable is \leq eight is conservative since the inoperable control rods are already

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

fully inserted). In addition, the control rods must be 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 C.2 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 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. 8) 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. A Note has been added to the Condition to clarify 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.

(continued)

BASES

ACTIONS
(continued)

E.1

In addition to the separation requirements for inoperable control rods, an assumption in the CRDA analysis for Framatome - ANP fuel is that no more than three inoperable control rods are allowed in any one BPWS group. Therefore, with one or more BPWS groups having four or more inoperable control rods, the control rods must be restored to OPERABLE status. Required Action E.1 is modified by a Note indicating that the Condition is not applicable when THERMAL POWER is > 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.

F.1

If any Required Action and associated Completion Time of Condition A, C, D, or E are not met or nine or more inoperable control rods exist, 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 (i.e., 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 conditions 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.3.1 (continued)

position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The 24 hour 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.

SR 3.1.3.2 and SR 3.1.3.3

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 than or equal the actual LPSP of the RWM 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). The 7 day Frequency of SR 3.1.3.2 is based on operating experience related to the changes in CRD performance and the ease of performing notch testing for fully withdrawn control rods. Partially withdrawn control rods are tested at a 31 day Frequency, based on the potential power reduction required to allow the control rod movement, and considering the large testing sample of SR 3.1.3.2. Furthermore, the 31 day Frequency takes into account operating experience related to changes in CRD performance. At any time, if a control rod is immovable, a determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

These SRs are modified by Notes that allow 7 days and 31 days respectively, after withdrawal of the control rod and increasing power to above the LPSP, to perform the Surveillance. This acknowledges that the control rod must be first withdrawn and THERMAL POWER must be increased to above the LPSP before performance of the Surveillance, and therefore the Notes avoid potential conflicts with SR 3.0.3 and SR 3.0.4.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.1.3.4

Verifying the scram time for each control rod to notch position 5 is ≤ 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, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. 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 demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.5

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 that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. 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 anytime 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.

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BASES (continued)

- REFERENCES
1. 10 CFR 50, Appendix A, GDC 26, GDC 27, GDC 28, and GDC 29.
 2. FSAR, Section 4.3.2.5.
 3. FSAR, Section 4.6.1.1.2.5.3.
 4. FSAR, Section 5.2.2.2.3.
 5. FSAR, Section 15.4.1.1.
 6. FSAR, Section 15.F.4.3.
 7. 10 CFR 50.36(c)(2)(ii).
 8. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.
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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 to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrambled 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 valves reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator or reactor pressure 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 accumulator pressure drops 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 within 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, 4, 5, and 6. The Design Basis Accident (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 scrambling slower than the average time, with several control rods scrambling faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's scram time averaged into each associated two-by-two array, 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 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), 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. 6) 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. 4), 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 Reference 7.

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. The scram times have a margin to allow up to eight of the control rods to have scram times that exceed the specified limits (i.e., "slow" control rods in a two-by-two array that do not meet the average scram time limits) 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 measurement of the "dropout" times.

Table 3.1.4-1 is modified by a Note, which states that control rods with scram times > 7 seconds are considered inoperable as required by SR 3.1.3.4.

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BASES

LCO
(continued)

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scrambling 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

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each two-by-two array. This is acceptable since the scram times are applicable for a two-by-two array, and the Required Actions for each Condition provide appropriate compensatory action for each two-by-two array not within the average scram time limits. Complying with the Required Actions may allow for continued operation and subsequent two-by-two arrays not within the average scram time limits governed by subsequent Condition entry and application of associated Required Actions.

A.1, A.2, and A.3

With one or more two-by-two arrays not within the average scram time limits of Table 3.1.4-1, the scram reactivity rate assumptions in the safety analysis may not be met. Therefore, each control rod in the two-by-two array, with a scram time slower than the average scram time limits must be declared "slow" immediately. To ensure the overall scram reactivity rate is met, the total number of "slow" and inoperable control rods must be immediately verified to be \leq eight. This ensures that the safety analysis assumptions are met (the safety analysis has sufficient margin to assume a total of eight control rods are "slow," one is stuck, and

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

another fails to scram. Therefore, ensuring the total number of "slow" and inoperable is \leq eight is conservative since the inoperable control rods are already fully inserted). To ensure the local scram reactivity rate is met, each "slow" control rod must be immediately verified to meet the "slow" control rod separation criteria. The "slow" control rod separation criteria are met if: a) the "slow" control rod is separated in all directions from each "slow" control rod and each stuck control rod by any combination of two or more fully inserted control rods or OPERABLE, withdrawn control rods that are not "slow"; and b) two or less additional inoperable or "slow" control rods are in the same group as the "slow" control rod.

With the verifications described above performed satisfactorily, the scram reactivity rate assumptions in the safety analysis will be met and continued operation is allowed.

B.1

When any Required Action and associated Completion Time is 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.

SURVEILLANCE
REQUIREMENTS

The four 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.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

In addition, the scram times in Table 3.1.4-1 are the average of a two-by-two array. Therefore, a control rod scram time, as determined by the following SRs, must be factored into the average scram time for all applicable two-by-two arrays.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 800 psig demonstrates acceptable scram times for the transients analyzed in References 5 and 6.

Maximum scram insertion times occur at a reactor pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the 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 scram time testing is performed within a reasonable time following a refueling or after a shutdown ≥ 120 days, all control rods are required to be tested before exceeding 40% RTP. 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.

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be "slow." If more than 7.5% of the sample is declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (i.e., 7.5% of the entire sample size) is

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.4.2 (continued)

satisfied, or until the total number of "slow" control rods (throughout the core, from all Surveillances) exceeds the LCO limit taken. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data were previously tested in a sample. The 200 day Frequency is based on operating experience that has shown control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable, based on the additional Surveillances done on the CRDs at more frequent intervals in accordance with LCO 3.1.3 and LCO 3.1.5, "Control Rod Scram Accumulators."

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate that the affected control rod is still within acceptable limits. The limits for reactor pressures < 800 psig are found in the Licensee Controlled Specifications Manual (Ref. 8), and are established based on a high probability of meeting the acceptance criteria at reactor pressures \geq 800 psig. Limits for \geq 800 psig are found in Table 3.1.4-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of the Note to Table 3.1.4-1, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times include (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator isolation valve, or check valves in the piping required for scram.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.4.3 (continued)

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability of testing the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

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. Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 will be satisfied with one test. For a control rod affected by work performed while shut down, however, a zero pressure and a high pressure test may be required. This testing ensures that the control rod scram performance is acceptable for operating reactor pressure conditions prior to withdrawing the control rod for continued operation. Alternatively, a 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 of testing the control rod at the different conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. FSAR, Section 4.3.2.5.
3. FSAR, Section 4.6.1.1.2.5.3.
4. FSAR, Section 5.2.2.2.3.
5. FSAR, Section 15.4.1.1.

(continued)

BASES

REFERENCES
(continued)

6. FSAR, Section 15.F.4.3.
 7. 10 CFR 50.36(c)(2)(ii).
 8. Licensee Controlled Specifications Manual.
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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, 3, 4, and 5. 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 the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). Also, 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 Reference 6.

(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 under 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 action 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 ≥ 900 psig, the control rod may be declared "slow" (after declaring the average scram time in all two-by-two arrays associated with the control rod with the inoperable accumulator not within the limits of Table 3.1.4-1), 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, which clarifies that declaring the control rod "slow" is only applicable if the average scram times of the two-by-two arrays associated with the control rod with the inoperable accumulator are within the limits of Table 3.1.4-1 during the last scram time Surveillance. Otherwise, the control rod may already be considered "slow"

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 entered. This would result in requiring the affected control rod to 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 considered 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 ≥ 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 20 minutes 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 20 minutes is considered a reasonable time to place a CRD pump into service to restore the charging header pressure, if required. This Completion Time also recognizes the ability of the reactor pressure alone to fully insert all control rods.

The control rod may be declared "slow" (after declaring the average scram time in all two-by-two arrays associated with the control rod with the inoperable accumulator not within the limits of Table 3.1.4-1), 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" is only applicable if the average scram times of the two-by-two arrays associated with the control rod with the inoperable accumulator are within the limits of

(continued)

BASES

ACTIONS B.1, B.2.1, and B.2.2 (continued)

Table 3.1.4-1 during the last scram time Surveillance. Otherwise, the control rod may 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 satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is considered 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 scram 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 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. This Required Action is modified by a Note stating that the Required 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 every 7 days to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of 1400 psig to 1500 psig (Ref. 7). Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. FSAR, Section 4.3.2.5.
 2. FSAR, Section 4.6.1.1.2.5.3.
 3. FSAR, Section 5.2.2.2.3.
 4. FSAR, Section 15.4.1.1.
 5. FSAR, Section 15.F.4.3.
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(continued)

BASES

REFERENCES
(continued)

6. 10 CFR 50.36(c)(2)(ii).
 7. FSAR, Section 4.6.1.1.2.4.1.
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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 effectively 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 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. 6 and 7) 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. 8) 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 2 follow the banked position withdrawal sequence (BPWS) described in Reference 9. The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 1). 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 defined to minimize the maximum incremental control rod worths without being overly restrictive during normal plant operation. The generic BPWS analysis (Ref. 9) also evaluated 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.

Rod pattern control satisfies the requirements of Criterion 3 of Reference 10.

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 \leq 10% RTP, the CRDA is a Design Basis Accident (DBA) 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. 1). 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.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, action 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 $\leq 10\%$ 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 (Reactor Operator or Senior Reactor Operator) or by a qualified member of the technical staff. This ensures 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 should 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 that allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Reactor Operator or Senior Reactor Operator) or by a qualified member of the technical staff.

With nine or more OPERABLE control rods not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the reactor mode switch in shutdown, the reactor is shut down, and therefore does not meet the applicability requirements of this LCO. 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.

SURVEILLANCE
REQUIREMENTS

SR 3.1.6.1

The control rod pattern is verified to be in compliance with the BPWS at a 24 hour Frequency, ensuring the assumptions of the CRDA analyses are met. The 24 hour Frequency of this Surveillance was developed considering that the primary check of the control rod pattern compliance with the BPWS is performed by the RWM (LCO 3.3.2.1). The RWM provides control rod blocks to enforce the required control rod sequence and is required to be OPERABLE when operating at $\leq 10\%$ RTP.

REFERENCES

1. Letter from T.A. Pickens (BWROG) to G.C. Laines (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1988.
2. FSAR, Section 15.4.9.
3. NUREG-0979, "NRC Safety Evaluation Report for GESSAR II BWR/6 Nuclear Island Design, Docket No. 50-447," Section 4.2.1.3.2, April 1983.

(continued)

BASES

REFERENCES
(continued)

4. NUREG-0800, "Standard Review Plan," Section 15.4.9, "Radiological Consequences of Control Rod Drop Accident (BWR)," Revision 2, July 1981.
 5. 10 CFR 50.67, "Accident Source Term."
 6. NEDO-10527, "Rod Drop Accident Analysis for Large BWRs," (including Supplements 1 and 2), March 1972.
 7. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.
 8. ASME, Boiler and Pressure Vessel Code, Section III.
 9. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.
 10. 10 CFR 50.36(c)(2)(ii).
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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. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System is also used to maintain suppression pool pH at or above 7 following a loss of coolant accident (LOCA) involving significant fission product releases. Maintaining suppression pool pH levels at or above 7 following an accident ensures that iodine will be retained in the suppression pool water (Ref. 4).

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves, which 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 through the high pressure core spray system sparger.

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 not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject, using both SLC pumps, a quantity of boron that produces a concentration of 660 ppm of natural boron in the reactor core, including recirculation loops, at 70°F and normal reactor water level.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

To allow 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). An additional 275 ppm is provided to accommodate dilution in the RPV by the residual heat removal shutdown cooling piping. The temperature versus concentration limits in Figure 3.1.7-1 are calculated such that the required concentration is achieved. 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.

Following a LOCA, offsite doses from the accident will remain within 10 CFR 50.67, "Accident Source Term," limits (Ref. 5) provided sufficient iodine activity is retained in the suppression pool. Credit for iodine deposition in the suppression pool is allowed (Ref. 4) as long as suppression pool pH is maintained at or above 7. Alternative Source Term analyses credit the use of the SLC System for maintaining the pH of the suppression pool at or above 7.

The SLC System satisfies Criteria 3 and 4 of Reference 3.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control, independent of normal reactivity control provisions provided by the control rods. Additionally, an OPERABLE SLC System has the ability to inject boron under post LOCA conditions to maintain the suppression pool pH above 7. 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 containing an OPERABLE pump, an explosive valve and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

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 the reactor remains subcritical. In MODE 5, only a

(continued)

BASES

APPLICABILITY
(continued)

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 perform its ATWS function during MODES 3, 4, or 5.

In MODES 1, 2, and 3, the SLC System must be OPERABLE to ensure that offsite doses remain within 10 CFR 50.67 (Ref. 5) limits following a LOCA involving significant fission product releases. The SLC System is used to maintain suppression pool pH at or above 7 following a LOCA to ensure that iodine will be retained in the suppression pool water (Ref. 4).

ACTIONS

A.1

If one SLC System 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 a Design Basis Accident (DBA) or severe transient occurring concurrent with the failure of the Control Rod Drive 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 a DBA or transient occurring concurrent with the failure of the control rods to shut down the reactor.

(continued)

BASES

ACTIONS
(continued)

C.1 and C.2

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 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 3.1.7.1 and SR 3.1.7.2

SR 3.1.7.1 and SR 3.1.7.2 are 24 hour Surveillances, verifying certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring the SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure the proper borated solution and temperature 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. The 24 hour Frequency of these SRs is based on operating experience that has shown there are relatively slow variations in the measured parameters of volume and temperature.

SR 3.1.7.3 and SR 3.1.7.5

SR 3.1.7.3 verifies the continuity of the explosive charges in the injection valves to ensure 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 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.1.7.5 verifies each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual and power operated valves in the SLC System flow path ensures that the proper flow paths will exist for system

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.7.3 and SR 3.1.7.5 (continued)

operation. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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 positions. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensure correct valve positions.

SR 3.1.7.4

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure the proper concentration of boron (measured in weight % sodium pentaborate decahydrate) exists in the storage tank. SR 3.1.7.4 must be performed anytime boron or water is added to the storage tank solution to establish that the boron solution concentration is within the specified limits. This Surveillance must be performed anytime the temperature is restored to within the limits of Figure 3.1.7-1, to ensure no significant boron precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances.

SR 3.1.7.6

Demonstrating each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1220 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.1.7.6 (continued)

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 tests confirm component OPERABILITY 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 pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months, at alternating 24 month intervals. 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Demonstrating that all heat traced piping between the boron solution storage tank and the suction valve to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.7.7 and SR 3.1.7.8 (continued)

acceptable method for verifying that the suction piping up to the suction valve is unblocked is to pump from the storage tank to the test tank. Upon completion of this verification, the pump suction piping must be drained and flushed with demineralized water since the suction piping between the pump suction valve and pump suction is not heat traced. The 24 month 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. However, if, in performing SR 3.1.7.1, it is determined that the temperature of the solution in the storage tank has fallen below the specified minimum, SR 3.1.7.8 must be performed once within 24 hours after the solution temperature is restored within the limits of Figure 3.1.7-1.

REFERENCES

1. 10 CFR 50.62.
 2. FSAR, Section 9.3.5.3.
 3. 10 CFR 50.36(c)(2)(ii).
 4. Regulatory Guide 1.183, July 2000.
 5. 10 CFR 50.67, "Accident Source Term."
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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. The SDV consists of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two 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. Each header is connected to a common vent line with two valves in series. 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 the control rods are capable of scrambling. The primary function of the SDV is to limit the amount of reactor coolant discharged during a scram. 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 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) and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves also allow continuous drainage of the SDV during normal plant

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

operation to ensure 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 exceeds a specified setpoint. The setpoint is chosen such 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 Reference 4.

LCO

The OPERABILITY of all SDV vent and drain valves ensures that, during a scram, the SDV vent and drain valves will close 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 be open 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, and 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. 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 a Note 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 allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS
(continued)

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 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 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 during the time the valve(s) are inoperable and the line(s) 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.

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 3.1.8.1

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 function 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. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation, which ensure correct valve positions. Improper valve position (closed) would not affect the isolation function.

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 92 day Frequency is based on operating experience and takes into account the level of redundancy in the system design.

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 a receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis. 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, "Control Rod-OPERABILITY," overlap this Surveillance to provide complete testing of the assumed safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.8.3 (continued)

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 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 4.6.1.1.2.4.2.5.
 2. 10 CFR 50.67, "Accident Source Term."
 3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.
 4. 10 CFR 50.36(c)(2)(ii).
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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 average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that the fuel design limits identified in References 1 and 2 are not exceeded and 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. As a result, core geometry will be maintained by minimizing gross fuel cladding failure due to heatup following a design basis LOCA.

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) and normal operations that determine APLHGR limits are presented in FSAR, Chapters 4, 6, 15, and 15.F and in References 1 and 2.

LOCA analyses are performed to ensure that the specified APLHGR limits 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 codes is provided in References 1 and 2. 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 APLHGR limits specified 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 APLHGR. For single recirculation loop operation, APLHGR limits are determined when two-loop limits are not bounding.

The APLHGR satisfies Criterion 2 of Reference 3.

(continued)

BASES (continued)

LCO

The APLHGR limits specified in the COLR are the result of the fuel design and design basis accident analyses. Limits have been provided in the COLR for two recirculation loop operation and single recirculation loop operation. The limits on single recirculation loop operation are provided to allow operation in this condition in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating."

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA analyses that are assumed to occur at high power levels. Studies 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, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels \leq 25% RTP, the reactor operates with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA analyses may not be met. Therefore, prompt action is taken to restore the APLHGR(s) to within the required limits such that the plant will be operating within analyzed conditions and within the 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 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 $<$ 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to $<$ 25% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is \geq 25% RTP and then every 24 hours 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 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER \geq 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. EMF-2361(P)(A) Revision 0, "EXEM BWR-2000 ECCS Evaluation Model," Framatome ANP Richland, May 2001
 2. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
 3. 10 CFR 50.36(c)(2)(ii).
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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 boiling transition to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid boiling transition 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 anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experiences boiling transition (Reference 1), the critical power at which boiling transition 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 AOOs to establish the operating limit MCPR are presented in the FSAR, Chapters 4, 6, and 15, and References 2 and 3. 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 pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (Δ CPR). When the largest Δ CPR is added to the MCPR SL, the required operating limit MCPR is obtained.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state (MCPR_r and MCPR_p, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency as identified in FSAR, Chapters 15 and 15.F.

Flow dependent MCPR limits are determined by steady-state thermal hydraulic methods using the three-dimensional BWR simulator code (Reference 2) and a multi-channel thermal-hydraulic code (Reference 3). MCPR_r curves are provided based on the maximum credible flow runout transient for ASD operation (i.e., runout of both loops).

Power dependent MCPR limits (MCPR_p) are determined by the three-dimensional BWR simulator code (Reference 2) and a multi-channel thermal-hydraulic code (Reference 3). 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 scram trips are bypassed, high and low flow MCPR_p operating limits are provided for operating between 25% RTP and the previously mentioned bypass power level.

The MCPR satisfies Criterion 2 of Reference 4.

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. MCPR operating limits that include the effects of analyzed equipment out-of-service are also included in the COLR. The MCPR operating limits are determined by the larger of the MCPR_r 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 25% RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs.

(continued)

BASES

APPLICABILITY
(continued)

Statistical analyses indicate that the nominal value of the initial MCPR at 25% RTP is expected to be very large. 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 25% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% 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 the 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 < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

(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 25% RTP and then every 24 hours 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 24 hour 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 reaches \geq 25% RTP is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. ANF-524(P)(A) Revision 2 and Supplements 1 and 2, "ANF Critical Power Methodology for Boiling Water Reactors," Advanced Nuclear Fuels, November 1990.
 2. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, "Exxon Nuclear Methodology for Boiling Water Reactors - Neutronic Methods for Design and Analysis," Exxon Nuclear Company, March 1983.
 3. XN-NF-80-19(P)(A) Volume 3 Revision 2, "Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX: Thermal Limits Methodology Summary Description," January 1987.
 4. 10 CFR 50.36(c)(2)(ii).
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B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on the LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (A00s). Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure or inability to cool the fuel does not occur during the anticipated operating conditions identified in References 1 and 2.

APPLICABLE
SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 3, 4, 5, and 6. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 50.67. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

- a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and
- b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Reference 7).

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to the operating limit specified in the COLR. The analysis also includes allowances for short term transient operation above the operating limit to account for A00s.

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The LHGR satisfies Criterion 2 of Reference 8.

LCO

The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at \geq 25% RTP.

ACTIONS

A.1

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR 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 < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.2.3.1

The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is \geq 25% RTP and then every 24 hours thereafter. They are compared with the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER \geq 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

REFERENCES

1. FSAR, Chapter 4.
 2. FSAR, Chapter 15.
 3. CENPD-287-P-A, "Fuel Assembly Design Methodology for Boiling Water Reactors," ABB Combustion Engineering Nuclear Operations, July 1996.
 4. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," ABB Combustion Engineering Nuclear Operations, July 1996.
 5. ANF-89-98(P)(A) Revision 1 and Supplement 1, Generic Mechanical Design Criteria for BWR Fuel Designs," Advanced Nuclear Fuels Corporation, May 1995.
 6. EMF-85-74(P) Revision 0 Supplement 1 (P)(A) and Supplement 2 (P)(A), "RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model," Siemens Nuclear Power Corporation, February 1998.
 7. NUREG-0800, Section II A.2(g), Revision 2, July 1981.
 8. 10 CFR 50.36(c)(2)(ii).
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B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 Average Power Range Monitor (APRM) Gain and Setpoint

BASES

BACKGROUND

The OPERABILITY of the APRMs and their setpoints is an initial condition of all safety analyses that assume rod insertion upon reactor scram. Applicable GDCs are GDC 10, "Reactor Design"; GDC 13, "Instrumentation and Control"; GDC 20, "Protection System Functions"; and GDC 29, "Protection against Anticipated Operation Occurrences" (Ref. 1). This LCO is provided to require the APRM gain or APRM flow biased scram setpoints to be adjusted when operating under conditions of excessive power peaking to maintain acceptable margin to the fuel cladding integrity Safety Limit (SL) and the fuel cladding 1% plastic strain limit.

The condition of excessive power peaking is determined by the ratio of the actual power peaking to the limiting power peaking at RTP. This ratio is equal to the ratio of the core limiting MFLPD to the Fraction of RTP (F RTP) where F RTP is the measured THERMAL POWER divided by the RTP. Excessive power peaking exists when:

$$\frac{\text{MFLPD}}{\text{F RTP}} > 1,$$

indicating that MFPLD is not decreasing proportionately to the overall power reduction, or conversely, that power peaking is increasing. To maintain margins similar to those at RTP conditions, the excessive power peaking is compensated by gain adjustment on the APRMs or adjustment of the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b). Either of these adjustments has effectively the same result as maintaining MFLPD less than or equal to F RTP and thus maintains RTP margins for APLHGR, MCPR, and LHGR.

The normally selected APRM Flow Biased Simulated Thermal Power—High Function Allowable Value positions the scram above the upper bound of the normal power/flow operating region that has been considered in the design of the fuel rods. The Allowable Value is flow biased with a slope that approximates the upper flow control line. The normally

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BASES

BACKGROUND
(continued)

selected APRM Allowable Value is supported by the analyses presented in References 1 and 2 that concentrate on events initiated from rated conditions. Design experience has shown that minimum deviations occur within expected margins to operating limits (APLHGR, MCPR, and LHGR), at rated conditions for normal power distributions. However, at other than rated conditions, control rod patterns can be established that significantly reduce the margin to thermal limits. Therefore, the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value may be reduced during operation when the combination of THERMAL POWER and MFLPD indicates an excessive power peaking distribution.

The APRM neutron flux signal is also adjusted to more closely follow the fuel cladding heat flux during power transients. The APRM neutron flux signal is a measure of the core thermal power during steady state operation. During power transients, the APRM signal leads the actual core thermal power response because of the fuel thermal time constant. Therefore, on power increase transients, the APRM signal provides a conservatively high measure of core thermal power. By passing the APRM signal through an electronic filter with a time constant less than, but approximately equal to, that of the fuel thermal time constant, an APRM transient response that more closely follows actual fuel cladding heat flux is obtained, while a conservative margin is maintained. The delayed response of the filtered APRM signal allows the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value to be positioned closer to the upper bound of the normal power and flow range, without unnecessarily causing reactor scrams during short duration neutron flux spikes. These spikes can be caused by insignificant transients such as performance of main steam line valve surveillances or momentary flow increases of only several percent.

APPLICABLE
SAFETY ANALYSES

The acceptance criteria for the APRM gain or setpoint adjustments are that acceptable margins (to APLHGR, MCPR, and LHGR) be maintained to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

FSAR safety analyses (Ref. 2) concentrate on the rated power condition for which the minimum expected margin to the operating limits (APLHGR, MCPR, and LHGR) occurs.
LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

(APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR) limit the initial margins to these operating limits at rated conditions so that specified acceptable fuel design limits are met during transients initiated from rated conditions. At initial power levels less than rated levels, the margin degradation of either the APLHGR, the MCPR, or the LHGR during a transient can be greater than at the rated condition event. This greater margin degradation during the transient is primarily offset by the larger initial margin to limits at the lower than rated power levels. However, power distributions can be hypothesized that would result in reduced margins to the pre-transient operating limit. When combined with the increased severity of certain transients at other than rated conditions, the SLs could be approached. At substantially reduced power levels, highly peaked power distributions could be obtained that could reduce thermal margins to the minimum levels required for transient events. To prevent or mitigate such situations, either the APRM gain is adjusted upward by the ratio of the core limiting MFLPD to the F RTP, or the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value is required to be reduced by the ratio of F RTP to the core limiting MFLPD. Either of these adjustments effectively counters the increased severity of some events at other than rated conditions by proportionally increasing the APRM gain or proportionally lowering the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value dependent on the increased peaking that may be encountered.

The APRM gain and setpoint satisfy Criteria 2 and 3 of Reference 3.

LCO

Meeting any one of the following conditions ensures acceptable operating margins for events described above:

- a. Limiting excess power peaking;
- b. Reducing the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value by multiplying the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value by the ratio of F RTP and the core limiting value of MFLPD; or

(continued)

BASES

LCO
(continued)

- c. Increasing the APRM gains to cause the APRM to read greater than 100(%) times MFLPD. This condition is to account for the reduction in margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

MFLPD is the ratio of the limiting LHGR to the LHGR limit for the specific bundle type. For Framatome ANP fuel, MFDLRX is the equivalent of MFLPD. As power is reduced, if the design power distribution is maintained, MFLPD is reduced in proportion to the reduction in power. However, if power peaking increases above the design value, the MFLPD is not reduced in proportion to the reduction in power. Under these conditions, the APRM gain is adjusted upward or the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value is reduced accordingly. When the reactor is operating with peaking less than the design value, it is not necessary to modify the APRM Flow Biased Simulated Thermal Power-High Function Allowable Value. Adjusting the APRM gain or modifying the Flow Biased Simulated Thermal Power-High Function Allowable Value is equivalent to maintaining MFLPD less than or equal to FRTP, as stated in the LCO.

For compliance with LCO Item b (APRM Flow Biased Simulated Thermal Power-High Function Allowable Value modification) or Item c (APRM gain adjustment), only APRMs required to be OPERABLE per LCO 3.3.1.1, Function 2.b, are required to be modified or adjusted. In addition, each APRM may be allowed to have its gain or Allowable Value adjusted or modified independently of other APRMs that are having their gain or Allowable Value adjusted or modified.

APPLICABILITY

The MFLPD limit, APRM gain adjustment, or APRM Flow Biased Simulated Thermal Power-High Function Allowable Value modification is provided to ensure that the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit are not violated during design basis transients. As discussed in the Bases for LCO 3.2.1, LCO 3.2.2, and LCO 3.2.3, sufficient margin to these limits exists below 25% RTP and, therefore, these requirements are only necessary when the plant is operating at \geq 25% RTP.

(continued)

BASES (continued)

ACTIONS

A.1

If the APRM gain or Flow Biased Simulated Thermal Power-High Function Allowable Value is not within limits while the MFLPD has exceeded F RTP, the margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit may be reduced. Therefore, prompt action should be taken to restore the MFLPD to within its required limit or make acceptable APRM adjustments such that the plant is operating within the assumed margin of the safety analyses.

The 6 hour Completion Time is normally sufficient to restore either the MFLPD to within limits or the APRM gain or Flow Biased Simulated Thermal Power-High Function Allowable Value to within limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LCO not met.

B.1

If the APRM gain or Flow Biased Simulated Thermal Power-High Function Allowable Value cannot be restored to within their 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 < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.2.4.1 and SR 3.2.4.2

The MFLPD is required to be calculated and compared to F RTP or APRM gain or Flow Biased Simulated Thermal Power-High Function Allowable Value to ensure that the reactor is operating within the assumptions of the safety analysis. These SRs are required only to determine the MFLPD and, assuming MFLPD is greater than F RTP, the appropriate APRM gain or Flow Biased Simulated Thermal Power-High Function Allowable Value, and is not intended to be a CHANNEL FUNCTIONAL TEST for the APRM gain or APRM Flow Biased Simulated Thermal Power-High Function circuitry. The 24 hour Frequency of SR 3.2.4.1 is chosen to coincide with

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.2.4.1 and SR 3.2.4.2 (continued)

the determination of other thermal limits, specifically those for the APLHGR and LHGR (LCO 3.2.1 and LCO 3.2.3, respectively). The 24 hour 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 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

The 12 hour Frequency of SR 3.2.4.2 is required when MFLPD is greater than FRTP, because more rapid changes in power distribution are typically expected.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 13, GDC 20, and GDC 29.
 2. FSAR, Chapters 15 and 15.F.
 3. 10 CFR 50.36(c)(2)(ii).
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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 limit to preserve the integrity of the fuel cladding and the reactor coolant pressure boundary (RCPB) and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). 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).

The RPS, as described in the FSAR, Section 7.2 (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 governor valve (TGV) fast closure, trip oil pressure low; turbine throttle valve (TTV) position; primary containment 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. Most channels include equipment (e.g., pressure switches) that compares measured input signals with pre-established setpoints. When a setpoint is exceeded, the channel outputs an RPS trip signal to the trip logic.

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A1 and A2, B1 and B2), as shown in

(continued)

BASES

BACKGROUND
(continued)

Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so 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 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.

Two pilot scram valves are located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each pilot scram valve is solenoid operated, with the solenoids normally energized. The pilot scram valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either pilot scram valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both pilot scram 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 pilot scram 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.

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 2, 3, 4, and 5. The RPS initiates a reactor scram 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.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

RPS instrumentation satisfies Criterion 3 of Reference 6. 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 appropriate.

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., differential pressure switch) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

The OPERABILITY of pilot scram valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

The individual Functions are required to be OPERABLE in the MODES or other specified conditions specified in the Table that 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 is required in each MODE to provide primary and diverse initiation signals.

The only MODES specified in Table 3.3.1.1-1 are MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No RPS Function is required in MODES 3 and 4 since 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. In MODE 5, 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, no RPS Function is 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.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1.a. Intermediate Range Monitor (IRM) Neutron Flux-High

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) 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 operating 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 from 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. 7). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, a generic analysis has been performed (Ref. 8) to evaluate

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 1.a. Intermediate Range Monitor (IRM) Neutron Flux-High
(continued)

the consequences of control rod withdrawal 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 enthalpy 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 four IRM channels inputting to each trip system. The analysis of Reference 7 assumes that one channel in each trip system is bypassed. Therefore, six channels with three 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 7 has adequate conservatism to permit the IRM Allowable Value specified in the Table.

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, the RWM and Rod Block Monitor provide protection against control rod withdrawal error events and the IRMs are not required. The IRMs are automatically bypassed when the mode switch is in the run position.

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BASES

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LCO, and
APPLICABILITY
(continued)

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, loss of the negative DC voltage, or 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 inoperative 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.

Six channels of Intermediate Range Monitor - Inop with three 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.

2.a. Average Power Range Monitor Neutron Flux - High, Setdown

The APRM channels receive input signals from the local power range monitors (LPRM) within the reactor core, which 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 greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux - High, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux - High, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron

(continued)

BASES

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LCO, and
APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High,
Setdown (continued)

Flux-High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux-High, Setdown Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux-High, Setdown Function. However, this Function indirectly ensures that, before the reactor mode switch is placed in the run position, reactor power does not exceed 25% 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 < 25% 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-High, Setdown, 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 coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The Average Power Range Monitor Neutron Flux-High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn. In MODE 1, the Average Power Range Monitor Neutron Flux-High Function provides protection against reactivity transients and the RWM and Rod Block Monitor protect against control rod withdrawal error events.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

2.b. Average Power Range Monitor Flow Biased Simulated
Thermal Power-High

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. 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) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux-High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux-High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function setpoint is exceeded.

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 Average Power Range Monitor channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Flow Biased Simulated Thermal Power-High, with two channels in each trip system arranged in 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 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power - High (continued)

Each APRM channel receives two independent, redundant flow signals representative of total recirculation driving flow. The total recirculation driving 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 the flow signals from the two recirculation loops. These redundant flow signals are sensed from four pairs of elbow taps, two in each recirculation loop. To obtain the most conservative reference signals under single failure conditions, 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 circuit selects the lower of the two flow unit signals for use as the reference for that particular APRM. Each required Average Power Range Monitor Flow Biased Simulated Thermal Power - 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 as described above for the Function, at least one required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channel in each trip system must be capable of maintaining an OPERABLE flow unit signal in the event of a failure of an auction circuit, or a flow unit, in the associated trip system (e.g., if a flow unit is inoperable, one of the two required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channels in the associated trip system must be considered inoperable).

No specific safety analyses take direct credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function. Originally, the clamped Allowable Value was based on analyses that took credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function for the mitigation of the loss of feedwater heater event. However, the current methodology for this event is based on a steady state analysis that allows power to increase beyond the clamped Allowable Value. Therefore,

(continued)

BASES

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LCO, and
APPLICABILITY

2.b. Average Power Range Monitor Flow Biased Simulated
Thermal Power-High (continued)

applying a clamp is conservative. The THERMAL POWER time constant of ≤ 7 seconds is based on the fuel heat transfer dynamics and provides a signal that is proportional to the THERMAL POWER.

The Average Power Range Monitor Flow Biased Simulated Thermal Power-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 Fixed Neutron Flux-High

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 Fixed Neutron Flux-High Function is capable of generating a trip signal to prevent fuel damage or excessive Reactor Coolant System (RCS) pressure. For the overpressurization protection analyses of References 2 and 3, the Average Power Range Monitor Fixed Neutron Flux-High 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. 9) takes credit for the Average Power Range Monitor Fixed Neutron Flux-High 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 Fixed Neutron Flux-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

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APPLICABILITY

2.c. Average Power Range Monitor Fixed Neutron Flux-High
(continued)

adequate coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux-High 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. The Average Power Range Monitor Fixed Neutron Flux-High Function is assumed in the CRDA analysis (Ref. 9) that is applicable in MODE 2. However, the Average Power Range Monitor Neutron Flux-High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux-High 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, or the APRM has too few LPRM inputs (< 14), 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.

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.

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BASES

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2.d. Average Power Range Monitor - Inop (continued)

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 result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analyses of References 2 and 3, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux - High signal, not the Reactor Vessel Steam Dome Pressure - High signal), along with the SRVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure switches 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 Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 since the RCS is pressurized and the potential for pressure increase exists.

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BASES

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APPLICABILITY
(continued)

4. Reactor Vessel Water Level - Low, Level 3

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 Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level - Low, Level 3 Function is assumed in the analysis of the recirculation line break (Ref. 4). 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, Level 3 signals are initiated from four differential pressure 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, Level 3 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, Level 3 Allowable Value is selected to ensure that, for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS at RPV Water Level 1 will not be required.

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, Level 2 and Low Low Low, Level 1 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

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APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY5. Main Steam Isolation Valve-Closure (continued)

are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analyses of References 2 and 3, the Average Power Range Monitor Fixed Neutron Flux-High 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 5 (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 two position switches; one inputs to RPS trip system A while the other inputs to RPS trip system B. Thus, each RPS trip system receives an input from eight Main Steam Isolation Valve-Closure channels, each consisting of one position switch. The logic for the Main Steam Isolation Valve-Closure Function is arranged such that either the inboard or outboard valve on three or more of the main steam lines (MSLs) must close in order for a scram to occur. In addition, certain combinations of valves closed in two lines will result in a half-scram.

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.

Sixteen channels of the Main Steam Isolation Valve-Closure Function with eight 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. In MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

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BASES

APPLICABLE
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LCO, and
APPLICABILITY
(continued)

6. Primary Containment 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 Primary Containment Pressure - High Function is a secondary scram signal to Reactor Vessel Water Level - Low, Level 3 for LOCA events inside the drywell. This function was not specifically credited in the accident analysis, but is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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.

High primary containment 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.

Four channels of Primary Containment Pressure - High Function, 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. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

7.a, b. 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 when the remaining free volume is still sufficient to accommodate the water from a full core scram. However, even though the two types of Scram Discharge Volume Water Level - High Function 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 FSAR. However, they are retained to ensure that the RPS remains OPERABLE.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

7.a, b. Scram Discharge Volume Water Level-High
(continued)

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 transmitters and trip units 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 transmitter and trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 10.

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 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 Throttle Valve-Closure

Closure of the TTVs 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 TTV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Throttle Valve-Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 5. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

Turbine Throttle Valve-Closure signals are initiated by valve stem position switches at each throttle valve. Two switches are associated with each throttle valve. One of the two provides input to RPS trip system A; the other, to

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

8. Turbine Throttle Valve-Closure (continued)

RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Throttle Valve-Closure channels, each consisting of one valve stem position switch. The logic for the Turbine Throttle Valve-Closure Function is such that three or more TTVs must close to produce a scram. In addition, certain combinations of two valves closed will result in a half-scram.

This Function must be enabled at THERMAL POWER \geq 30% RTP. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

The Turbine Throttle Valve-Closure Allowable Value is selected to detect imminent TTV closure thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Throttle 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 TTVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is \geq 30% RTP. This Function is not required when THERMAL POWER is $<$ 30% RTP since the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor Fixed Neutron Flux-High Functions are adequate to maintain the necessary safety margins.

9. Turbine Governor Valve Fast Closure, Trip Oil Pressure-Low

Fast closure of the TGVs 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 TGV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Governor Valve Fast Closure, Trip Oil Pressure-Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 5. For

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

9. Turbine Governor Valve Fast Closure, Trip Oil
Pressure-Low (continued)

this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Governor Valve Fast Closure, Trip Oil Pressure-Low signals are initiated by the digital-electro hydraulic fluid pressure at each governor valve. There is one pressure switch associated with each governor valve, the signal from each switch being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER \geq 30% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Throttle Valve-Closure Function.

The Turbine Governor Valve Fast Closure, Trip Oil Pressure-Low Allowable Value is selected high enough to detect imminent TGV fast closure.

Four channels of Turbine Governor 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 \geq 30% RTP. This Function is not required when THERMAL POWER is $<$ 30% RTP since the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor Fixed Neutron Flux-High Functions are adequate to maintain the necessary safety margins.

10. Reactor Mode Switch-Shutdown Position

The Reactor Mode Switch-Shutdown Position Function provides signals, via the manual scram logic channels, that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident

(continued)

BASES

APPLICABLE
SAFETY ANALYSIS,
LCO, and
APPLICABILITY

10. Reactor Mode Switch-Shutdown Position (continued)

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 four channels (one from each of the four independent banks of contacts), each of which inputs into one of the RPS logic channels.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

Four channels of Reactor Mode Switch-Shutdown Position Function, with two channels 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 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.

11. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, to each of the four RPS logic channels that are redundant to 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 four RPS logic channels. In order to cause a scram it is necessary that at least one channel in each trip system be actuated.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

(continued)

BASES

APPLICABLE
SAFETY ANALYSIS,
LCO, and
APPLICABILITY

11. Manual Scram (continued)

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic, 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. 11) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Functions 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 compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 11 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference 11, 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 as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, 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 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 MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Throttle 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 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.

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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 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 RPS reliability analysis (Ref. 11) 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 a CHANNEL CHECK once every 12 hours is the qualitative assessment, by observation, of channel behavior during operation. This assessment is the comparison, where possible, of the channel status or indication to the status or indication of an independent instrument measuring the same parameter. 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 significant deviation could indicate 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.1 (continued)

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 3.3.1.1.2

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 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. 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 MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.7.

A restriction to satisfying this SR when $< 25\%$ RTP is provided that requires the SR to be met only at $\geq 25\%$ RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when $< 25\%$ 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 $\geq 25\%$ RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 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. This allows entry into MODE 2 if the 7 day 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.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 11).

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 11. (The Manual Scram Functions CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions Frequencies.)

SR 3.3.1.1.5 and SR 3.3.1.1.6

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 region without adequate neutron flux

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.5 and SR 3.3.1.1.6 (continued)

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 (initiate a rod block) if adequate overlap is not maintained. 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. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block. The IRM/APRM and SRM/IRM overlaps are also acceptable if a $\frac{1}{2}$ decade overlap exists.

As noted, SR 3.3.1.1.6 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 channel(s) that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.7

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1130 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.8 and SR 3.3.1.1.13

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

For Function 2.b, the CHANNEL FUNCTIONAL TEST includes the adjustment of the APRM channel to conform to a calibrated flow signal. This ensures that the total loop drive flow signals from the flow unit used to vary the setpoint are appropriately compared to an injection test flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. If the flow signal trip setpoint is not within the appropriate limit, the APRMs that receive an input from the inoperable flow unit must be declared inoperable.

The 92 day Frequency of SR 3.3.1.1.8 is based on the reliability analysis of Reference 11. The 24 month 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 the 24 month Frequency.

SR 3.3.1.1.9 and SR 3.3.1.1.10

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.

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.9 and SR 3.3.1.1.10 (continued)

calorimetric calibration (SR 3.3.1.1.2) and the 1130 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.7). 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 moveable 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 Frequency of SR 3.3.1.1.9 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.10 is based on the assumption of an 18 month calibration interval for Functions 1 through 4, 6, 7, and 9 through 11 in the determination of the magnitude of equipment drift in the setpoint analysis.

A Frequency of 24 months is assumed for Functions 5 and 8 because the position switches that perform these Functions are not susceptible to instrument drift.

SR 3.3.1.1.11

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The filter time constant must be verified to ensure that the channel is accurately reflecting the desired parameter.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.12

This SR ensures that scrams initiated from the Turbine Throttle Valve-Closure and Turbine Governor Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq 30\%$ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the Allowable Value and 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 during an in-service calibration at THERMAL POWER $\geq 30\%$ RTP to ensure that the calibration is valid.

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at $\geq 30\%$ RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Throttle Valve-Closure and Turbine Governor 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 Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.14

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.14 (continued)

Surveillance was performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.15

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 acceptance criteria are included in Reference 12.

As noted (Note 1), neutron detectors for Function 2 are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. In addition, Note 2 states that channel sensors for Functions 3 and 4 are excluded and therefore, it is not required to quantitatively measure the sensor response time to satisfy the requirement to verify RPS RESPONSE TIME. This is acceptable since the sensor response time can be qualitatively verified by other methods (Ref. 13). If the response time of the sensor is not quantitatively measured, the acceptance criteria must be reduced by the time assumed for sensor response in the design analyses, as verified by statistical analyses or vendor data.

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 month 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 time degradation, but not channel failure, are infrequent.

(continued)

BASES (continued)

- REFERENCES
1. FSAR, Section 7.2.
 2. FSAR, Section 5.2.2.
 3. Columbia Generating Station Calculation NE-02-94-66, Revision 0, November 13, 1995.
 4. FSAR, Section 6.3.3.
 5. FSAR, Chapter 15.
 6. 10 CFR 50.36(c)(2)(ii).
 7. FSAR, Section 15.4.1.
 8. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
 9. FSAR, Section 15.4.9.
 10. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
 11. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
 12. Licensee Controlled Specifications Manual.
 13. NEDO 32291-A, "System Analyses for Elimination of Selected Response Time Testing Requirements, October 1995.
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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 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 to 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 3.3.1.1.5) and the IRMs are on Range 3, 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 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 are provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

System (RPS) Instrumentation," Intermediate Range Monitor (IRM) Neutron Flux High and Average Power Range Monitor (APRM) Neutron Flux-High, Setdown Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

The SRMs have no safety function and are not assumed to function during any 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 being retained in the 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, to monitor subcritical multiplication and reactor criticality, and to monitor neutron flux level and reactor period until the flux level is sufficient to maintain the IRMs on Range 3 or above. All channels but one 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 edges 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

(continued)

BASES

LCO
(continued)

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.

Special movable detectors, according to Table 3.3.1.2-1, footnote (c), 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 is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Providing that at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This is a reasonable time since there is adequate capability remaining to monitor the core, limited risk of an event during this time, and sufficient time to take corrective actions to restore the required SRMs to

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase are 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.

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to the 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, if the required number of SRMs is 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 in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or more required SRM channels 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

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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 SRM occurring during this time.

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the capability 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 condition are found in the SRs column of Table 3.3.1.2-1.

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 the same parameter indicated 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.2.1 and SR 3.3.1.2.3 (continued)

something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency of once every 12 hours for SR 3.3.1.2.1 is based on operating experience that demonstrates channel failure is rare. While in MODES 3 and 4, reactivity changes are not expected; therefore, the 12 hour Frequency is relaxed to 24 hours for SR 3.3.1.2.3. 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 this 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 (when the fueled region encompasses only one SRM), per Table 3.3.1.2-1, footnote (b), 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 12 hour Frequency is based upon operating experience and supplements operational controls over refueling activities, which include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)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 full in. This ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRMs will 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 quadrant, even with a control rod withdrawn the configuration will not be critical.

The Frequency is based upon channel redundancy and other information available in the control room, and ensures that the required channels are frequently monitored while core reactivity changes are occurring. When no reactivity changes are in progress, the Frequency is relaxed from 12 hours to 24 hours.

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. SR 3.3.1.2.5 is required in MODE 5, and the 7 day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. This 7 day Frequency is reasonable, 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 only to control rod movement in MODE 2, the Frequency has been extended from 7 days to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.2.5 and SR 3.3.1.2.6 (continued)

31 days. The 31 day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

The signal to noise ratio is determined to ensure adequate SRM response to reactivity changes while shutdown. This determination is performed by comparing an SRM countrate including neutrons to an SRM countrate not including neutrons. One method is to compare the SRM countrate with the detector in the core to the SRM countrate with the SRM withdrawn from the core. Another method electronically eliminates the SRM countrate signal due to neutrons. This signal and a normal SRM signal are then compared to determine the signal to noise ratio.

With few fuel assemblies loaded, the SRMs will not have a high enough count rate to determine the signal to noise ratio. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the conditions necessary to determine the signal to noise ratio. To accomplish this, SR 3.3.1.2.5 is modified by a Note that states that the determination of signal to noise ratio 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, even with a control rod withdrawn the configuration will not be critical.

The Note to the SR 3.3.1.2.6 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 31 day 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.2.5 and SR 3.3.1.2.6 (continued)

otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM detectors and associated circuitry. 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. The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) 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 18 month 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 3.3.1.3 Oscillation Power Range Monitor (OPRM)

BASES

BACKGROUND

General Design Criterion 10 (GDC 10) requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the affects of anticipated operational occurrences. Additionally, GDC 12 requires the reactor core and associated coolant, control, and protection systems to be designed to assure that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit.

References 1, 2, and 3 describe three separate algorithms for detecting stability related oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. The OPRM System hardware implements these algorithms in microprocessor based modules. These modules execute the algorithms based on LPRM inputs and generate alarms and trips based on these calculations. These trips result in tripping the Reactor Protection System (RPS) when the appropriate RPS trip logic is satisfied, as described in the Bases for LCO 3.3.1.1, "RPS Instrumentation." Only the period based detection algorithm is used in the safety analysis. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations.

The period based detection algorithm detects a stability related oscillation based on the occurrence of a fixed number of consecutive LPRM signal period confirmations followed by the LPRM signal amplitude exceeding a specified setpoint. Upon detection of a stability related oscillation, a trip is generated for that OPRM channel.

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BASES

BACKGROUND
(continued)

The OPRM System consists of 4 OPRM trip channels, each channel consisting of two OPRM modules. Each OPRM module receives input from LPRMs. Each OPRM module also receives input from the Neutron Monitoring System (NMS) average power range monitor (APRM) power and flow signals to automatically enable the trip function of the OPRM module.

Each OPRM module is continuously tested by a self-test function. On detection of any OPRM module failure, either a trouble alarm or INOP alarm is activated. The OPRM module provides an INOP alarm when the self-test feature indicates that the OPRM module may not be capable of meeting its functional requirements.

APPLICABLE
SAFETY ANALYSES

It has been shown that BWR cores may exhibit thermal-hydraulic reactor instabilities in high power and low flow portions of the core power to flow operating domain. GDC 10 requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. GDC 12 requires assurance that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12 by detecting the onset of oscillations and suppressing them by initiating a reactor scram. This assures that the MCPR safety limit will not be violated for anticipated oscillations.

The OPRM Instrumentation satisfies Criteria 3 of the NRC Policy Statement.

LCO

Four channels of the OPRM System are required to be OPERABLE to ensure that stability related oscillations are detected and suppressed prior to exceeding the MCPR safety limit. Only one of the two OPRM modules' period based detection algorithm is required for OPRM channel OPERABILITY. The minimum number of LPRMs required OPERABLE to maintain an OPRM channel OPERABLE is consistent with the minimum number of LPRMs required to maintain the APRM system OPERABLE per

(continued)

BASES

LCO (continued) LCO 3.3.1.1. The Allowable Value for the OPRM Period Based Algorithm setpoint (Sp) is derived from Analytic Limit corrected for the instrument and calibration errors.

APPLICABILITY The OPRM instrumentation is required to be OPERABLE in order to detect and suppress neutron flux oscillations in the event of thermal-hydraulic instability. As described in References 1, 2, and 3, the power/core flow region protected against anticipated oscillations is defined by THERMAL POWER $\geq 30\%$ RTP and core flow $\leq 60\%$ rated core flow. The OPRM trip is required to be enabled in this region and the OPRM must be capable of enabling the trip function as a result of anticipated transients. Therefore, the OPRM is required to be OPERABLE with THERMAL POWER $\geq 25\%$ RTP. It is not necessary for the OPRM to be OPERABLE with THERMAL POWER $< 25\%$ RTP because transients from below this THERMAL POWER are not anticipated to result in power that exceeds 30% RTP.

ACTIONS A Note has been provided to modify the ACTIONS related to the OPRM 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 base on initial entry into the Condition. However, the Required Actions for inoperable OPRM 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 OPRM instrumentation channel.

A.1, A.2, and A.3

Because of the reliability and on-line self-testing of the OPRM instrumentation and the redundancy of the RPS design, an allowable out of service time of 30 days has been shown to be acceptable (Reference 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

service time is only acceptable provided the OPRM Instrumentation still maintains OPRM trip capability (refer to Required Actions B.1 and B.2). The remaining OPERABLE OPRM channels continue to provide trip capability (see Condition B) and provide operator information relative to stability activity. The remaining OPRM modules have high reliability. With this high reliability, there is a low probability of a subsequent channel failure within the allowable out of service time. In addition, the OPRM modules continue to perform on-line self-testing and alert the operator if any further system degradation occurs.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the OPRM channel or associated RPS trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable OPRM channel in trip (or the associated RPS trip system 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 OPRM channel (or RPS trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), the alternate method of detecting and suppressing thermal hydraulic instability oscillations is required (Required Action A.3). This alternate method is described in Reference 5. It consists of increased operator awareness and monitoring for neutron flux oscillations when operating in the region where oscillations are possible. If indications of oscillation, as described in Reference 5, are observed by the operator, the operator will take the actions described by procedures, which include initiating a manual scram of the reactor.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped OPRM channels within the same RPS trip system result in not maintaining OPRM trip capability. OPRM trip capability is considered to be maintained when sufficient OPRM channels are OPERABLE or in trip (or the associated RPS trip system is in trip), such that a valid OPRM signal will generate a

(continued)

BASES

ACTIONS

B.1 (continued)

trip signal in both RPS trip systems. This would require both RPS trip systems to have one OPRM channel OPERABLE or in trip (or the associated RPS trip system in trip).

Because of the low probability of the occurrence of an instability, 12 hours is an acceptable time to initiate the alternate method of detecting and suppressing thermal hydraulic instability oscillations described in Action A.3 above. The alternate method of detecting and suppressing thermal hydraulic instability oscillations would adequately address detection and mitigation in the event of instability oscillations. Based on industry operating experience with actual instability oscillation, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM System may still be available to provide alarms to the operator if the onset of oscillations were to occur. Since plant operation is minimized in areas where oscillations may occur, operation without OPRM trip capability is considered acceptable with implementation of the alternate method of detecting and suppressing thermal hydraulic instability oscillations during the period when corrective actions are underway to resolve the inoperability that led to entry into Condition B. One reason this Condition may be used is to provide time to implement a software upgrade in the plant if a common-cause software problem is identified.

C.1

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 25% RTP within 4 hours. Reducing THERMAL POWER to < 25% RTP places the plant in a region where instabilities cannot occur. The 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.3.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A Frequency of 184 days provides an acceptable level of system average availability over the Frequency and is based on the reliability of the channel (Reference 7).

SR 3.3.1.3.2

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the OPRM System. The 1130 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.3.3

The CHANNEL CALIBRATION is a complete check of the instrument loop. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology. Calibration of the channel provides a check of the internal reference voltage and the internal processor clock frequency. It also compares the desired trip setpoints with those in processor memory. Since the OPRM is a digital system, the internal reference voltage and processor clock frequency are, in turn, used to automatically calibrate the internal analog to digital converters. The Allowable Values are specified in the (COLR). As noted, 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 1130 MWD/T LPRM calibration using the TIPs (SR 3.3.1.3.2).

The Frequency of 24 months is based upon the assumption of the magnitude of equipment drift provided by the equipment supplier (Reference 7).

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.3.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod Operability," and in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function. The OPRM self-test function may be utilized to perform this testing for those components that it is designed to monitor.

The 24 month Frequency is based on engineering judgment and reliability of the components and Operating experience.

SR 3.3.1.3.5

This SR ensures that trips initiated from the OPRM System will not be inadvertently bypassed when THERMAL POWER is $\geq 30\%$ RTP and core flow is $\leq 60\%$ rated core flow. This normally involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoints (Reference 7).

If any bypass channel setpoint is nonconservative (i.e., the OPRM module is bypassed at $\geq 30\%$ RTP and core flow $\leq 60\%$ rated core flow), then the affected OPRM module is considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (Manual Enable). If placed in the Manual Enable condition, this SR is met and the module is considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.3.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis (Reference 6). The OPRM self-test function may be utilized to perform this testing for those components it is designed to monitor. The LPRM amplifier

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.3.6 (continued)

cards inputting to the OPRM are excluded from the OPRM response time testing. The RPS RESPONSE TIME acceptance criteria are included in Reference 8.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. This Frequency is based upon operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

REFERENCES

1. NEDO-31960-A, "BWR Owners Group Long-Term Stability Solutions Licensing Methodology," November 1995 (Sus) June 1991.
 2. NEDO 31960-A, Supplement 1 "BWR Owners Group Long-Term Stability Solutions Licensing Methodology," November 1995 (Sus) March 1992.
 3. NRC Letter, A. Thadani to L.A. England, "Acceptance for Referencing of Topical Reports NEDO-31960, Supplement 1, 'BWR Owners Group Long-Term Stability Solutions Licensing Methodology,'" July 12, 1994.
 4. Generic Letter 94-02, "Long-Term Solutions and Upgrade of Interim Operating Recommendations for Thermal-Hydraulic Instabilities in Boiling Water Reactors," July 11, 1994.
 5. BWROG Letter BWROG-94079, "Guidelines for Stability Interim Corrective Action," June 6, 1994.
 6. NEDO-32465-A, "BWR Owners' Group Reactor Stability Detect and Suppress Solution Licensing Basis Methodology and Reload Application," August 1996 & May 1995.
 7. CENPD-400-P, Rev 01, "Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)," May 1995.
 8. Licensee Controlled Specification Table 1.3.1.1-1
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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 (Ref. 1). 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. One RBM channel averages the signals from LPRM detectors at the A and C positions in the assigned LPRM assemblies, while the other RBM channel averages the signals from LPRM detectors at the B and D positions. Alignment of LPRM assemblies to be used in RBM averaging is controlled by the selection of control rods. The RBM is automatically bypassed and the output set to zero if a peripheral rod is selected or the APRM used to normalize the RBM reading is < 30% RTP. If any LPRM detector assigned to an RBM is bypassed, the computed average signal is automatically adjusted to compensate for the number of LPRM input signals. The minimum number of LPRM inputs required for each RBM

(continued)

BASES

BACKGROUND
(continued)

channel to prevent an instrument inoperative alarm is four when using four LPRM assemblies, three when using three LPRM assemblies, and two when using two LPRM assemblies. Each RBM also receives a recirculation loop flow signal from the APRM flow converters.

When a control rod is selected, the gain of each RBM channel output is normalized to an assigned APRM channel. The assigned APRM channel is on the same RPS trip system as the RBM channel. The gain setting is held constant during the movement of that particular control rod to provide an indication of the change in the relative local power level. If the indicated power increases above the preset limit, a rod block will occur. In addition, to preclude rod movement with an inoperable RBM, a downscale trip and an inoperable trip are provided.

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. A prescribed control rod sequence is 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 position indication for each control rod. The RWM also uses steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). The RWM is a single channel system that provides input into one RMCS rod block circuit.

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.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES,
LCD, 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.

The RBM Function satisfies Criterion 3 of Reference 4.

Two channels of the RBM are required to be OPERABLE, with their setpoints within the appropriate Allowable Values to ensure that no single instrument failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with applicable setpoint methodology.

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., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

1. Rod Block Monitor (continued)

The RBM is assumed to mitigate the consequences of an RWE event when operating $\geq 30\%$ RTP and a peripheral control rod is not selected. Below this power level, or if a peripheral control rod is selected, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Ref. 3).

2. Rod Worth Minimizer

The RWM enforces 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 Reference 5. The 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."

The RWM Function satisfies Criterion 3 of Reference 4.

Since the RWM is a 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. 6). 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 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 $\leq 10\%$ RTP. 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 (Ref. 5). 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

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
LCO, and
APPLICABILITY

2. Rod Worth Minimizer (continued)

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 Reference 4.

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 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

(continued)

BASES

ACTIONS

A.1 (continued)

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. 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 a reactor startup with an inoperable RWM during withdrawal of one or more of the first 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.

(continued)

BASES

ACTIONS C.1, C.2.1.1, C.2.1.2, and C.2.2 (continued)

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.

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.

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. The RWM may be bypassed under these conditions to allow the reactor shutdown to continue.

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

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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. 7) 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.

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the channel will perform the intended function. It includes the Reactor Manual Control Multiplexing System input.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 92 days is based on reliability analyses (Ref. 8).

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

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. 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 only, by attempting to select a control rod 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 MODE 1. This allows entry into MODE 2 (and if entering during a shutdown, concurrent power reduction to $\leq 10\%$ RTP) for SR 3.3.2.1.2, and THERMAL POWER reduction to $\leq 10\%$ RTP in MODE 1 for SR 3.3.2.1.3, to perform the required Surveillances if the 92 day 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 92 day Frequencies are based on reliability analysis (Ref. 8).

SR 3.3.2.1.4

The RBM is automatically bypassed when power is below a specified value or if a peripheral control rod is selected. The power level is determined from the APRM signals input to each RBM channel. The automatic bypass setpoint must be verified periodically to be $< 30\%$ RTP. In addition, it must also be verified that the RBM is not bypassed when a control rod that is not a peripheral control rod is selected (only one non-peripheral control rod is required to be verified). If any bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the APRM channel can be placed in the conservative condition (non-bypass). 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

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.2.1.4 (continued)

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 3.3.1.1.7. The 92 day 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. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific 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 3.3.1.1.7.

The Frequency is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from a steam flow signal. The automatic bypass setpoint must be verified periodically to be > 10% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The Frequency is based on instrument drift analysis and the trip setpoint methodology utilized for the low power setpoint channel.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.2.1.7

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. 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 24 month 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.2.1.8

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

REFERENCES

1. FSAR, Section 7.7.1.8.
2. FSAR, Section 7.7.1.10.
3. FSAR, Sections 15.4.1 and 15.4.2.

(continued)

BASES

REFERENCES
(continued)

4. 10 CFR 50.36(c)(2)(ii).
 5. FSAR, Section 15.4.9.
 6. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.
 7. GENE-770-06-1-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.
 8. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.
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B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The feedwater and main turbine high water level trip instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level, Level 8 reference point, causing the trip of the two feedwater pump turbines and the main turbine.

Reactor Vessel Water Level-High, Level 8 signals are provided by level sensors 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 in the reactor vessel (variable leg). Three channels of Reactor Vessel Water Level-High, Level 8 instrumentation are provided as input to a two-out-of-three initiation logic that trips the two feedwater pump turbines and the main turbine. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a main feedwater and main turbine trip signal to the trip logic.

A trip of the feedwater pump turbines limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the throttle valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The feedwater and main turbine high water level trip instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The Level 8 trip indirectly initiates a reactor scram from the main turbine trip (above 30% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

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BASES

APPLICABLE SAFETY ANALYSES Feedwater and main turbine high water level trip instrumentation satisfies Criterion 3 of Reference 2.
(continued)

LCO The LCO requires three channels of the Reactor Vessel Water Level-High, Level 8 instrumentation to be OPERABLE to ensure that no single instrument failure will prevent the feedwater pump turbines and main turbine trip on a valid Level 8 signal. Two of the three channels are needed to provide trip signals in order for the feedwater and main turbine trips to occur. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.3. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. 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 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., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

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BASES (continued)

APPLICABILITY The feedwater and main turbine high water level trip instrumentation is required to be OPERABLE at $\geq 25\%$ RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "Average Planar Linear Heat Generation Rate (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS A Note has been provided to modify the ACTIONS related to feedwater and main turbine high water level trip instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent trains, 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 feedwater and main turbine high water level trip 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 feedwater and main turbine high water level trip instrumentation channel.

A.1

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the

(continued)

BASES

ACTIONS

A.1 (continued)

inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in a feedwater or main turbine trip), Condition C must be entered and its Required Action taken.

The Completion Time of 7 days is based on the low probability of the event occurring coincident with a single failure in a remaining OPERABLE channel.

B.1

With two or more channels inoperable, the feedwater and main turbine high water level trip instrumentation cannot perform its design function (feedwater and main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which feedwater and main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient channels are OPERABLE or in trip such that the feedwater and main turbine high water level trip logic will generate a trip signal on a valid signal. This requires two channels to each be OPERABLE or in trip. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition C must be entered and its Required Action taken.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of feedwater and main turbine high water level trip instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCD 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

(continued)

BASES

ACTIONS
(continued)

C.1

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater and main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% 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 feedwater and main turbine high water level 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. 3) assumption that 6 hours is 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 feedwater pump turbines and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels, or

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.2.2.1 (continued)

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 limits.

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 the channels required by the LCO.

SR 3.3.2.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on reliability analysis (Ref. 3).

SR 3.3.2.2.3

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 Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.2.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater stop valves and main turbine throttle valves 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 valve is incapable of operating, the associated instrumentation would also be inoperable. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 15.F.1.2.
 2. 10 CFR 50.36(c)(2)(ii).
 3. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," December 1992.
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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, in the control room, plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events. The instruments that monitor these variables are designated as Type A, Category I, and non-Type A, Category I in accordance with Regulatory Guide 1.97 (Ref. 1).

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.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A, variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (EOP). These variables are restricted to preplanned actions for the primary success path of Design Basis Accidents (DBAs) (e.g., loss of coolant accident (LOCA)); and
- Take the specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for safety systems to accomplish their safety function.

The PAM instrumentation LCO also ensures OPERABILITY of Category I, non-Type A, variables. This ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

- 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 to obtain an estimate of the magnitude of any impending threat.

The plant specific Regulatory Guide 1.97 analysis (Ref. 2) documents the process that identified Type A and Category I, non-Type A, variables.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of Reference 3. Category I, non-Type A, instrumentation is retained in the Technical Specifications (TS) because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires two OPERABLE channels for most of the Functions to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident. Furthermore, providing two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exceptions of the two channel requirement are the primary containment isolation valve (PCIV) position and the ECCS Pump Room Flood Level. For the PCIV position, the important information is the status of the primary containment penetrations. The LCO requires one position indicator for each active (e.g., automatic) PCIV. This 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. If a normally active PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for closed and deactivated valves is not required

(continued)

BASES

LCO
(continued)

to be OPERABLE. For the ECCS Pump Room Flood Level one level switch is provided in each of the five ECCS pump rooms to monitor room flood conditions, due to leaks in the rooms.

Listed below is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1.

1. Reactor Vessel Pressure

Reactor vessel pressure is a Type A and 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 monitor pressure. Wide range 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.

2.a, 2.b. Reactor Vessel Water Level

Reactor vessel water level is a Type A and Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. Two different range channels (wide range and fuel zone range) provide the PAM Reactor Vessel Water Level Function. The water level channels measure from 60 inches above the bottom of the dryer skirt to 150 inches below the top of the active fuel. Water level is measured by independent differential pressure transmitters for each required channel. The output from these channels is recorded on independent pen recorders or read on indicators. These instruments are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

The reactor vessel water level instruments are uncompensated for variation in reactor water density and are calibrated to be most accurate at a specific vessel pressure and temperature. The wide range instruments are calibrated to be accurate at the normal operating pressure and temperature. The fuel zone range instruments are calibrated to be accurate at 0 psig and 212°F.

(continued)

BASES

LCO
(continued)

3.a, 3.b. 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. Two different range channels provide the PAM Suppression Pool Water Level Function. The wide range and narrow range suppression pool water level measurement provides the operator with sufficient information to assess the status of the RCPB and to assess the status of the water supply to the ECCS. The wide range water level indicators monitor the suppression pool level from the center line of the ECCS suction lines to the top of the pool (2 ft to 52 ft), while the narrow range water level indicators monitor the water level around its normal level (-25 inches to +25 inches). Two wide range and two narrow range suppression pool water level signals are transmitted from separate transmitters and are continuously recorded on two recorders in the control room. These 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.

4. Suppression Chamber Pressure

Suppression chamber pressure is a Type A and Category I variable provided to determine whether or not drywell spray initiation will be required, given a high drywell pressure condition. This variable is also used to indicate suppression pool spray flow has been established. Suppression chamber pressure is recorded in the control room from two separate pressure transmitter systems. The range of recording is from 0 psig to 100 psig. These 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.a, 5.b, 5.c. Drywell Pressure

Drywell pressure is a Type A and Category I variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Three different range drywell pressure channels receive signals

(continued)

BASES

LCO

5.a, 5.b, 5.c. Drywell Pressure (continued)

that are transmitted from separate pressure transmitters and are continuously recorded and displayed on two control room recorders. The range of recording is from -5 psig to 180 psig. These 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.

6. Primary Containment Area Radiation (High Range)

Primary containment area radiation (high range) is a Category I variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Two detectors are located inside containment that have a range from 10^0 R/hr to 10^7 R/hr. These monitors respond to gamma radiation of 60 KeV as required by Regulatory Guide 1.97 to see the Xe-133 gases. These radiation monitors display on recorders located in the control room. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

7. Primary Containment Isolation Valve (PCIV) Position

PCIV (excluding check valves) position 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 verify redundantly 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

(continued)

BASES

LCO

7. Primary Containment Isolation Valve (PCIV) Position
(continued)

penetration 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 is not required to be OPERABLE.

The indication for each PCIV is provided at the valve controls in the control room. Each indication consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

8. 9. Deleted

10. ECCS Pump Room Flood Level

ECCS pump room flood level is a Type A and Category I variable provided to indicate ECCS pump room flooding. High water level in the ECCS pump rooms is indicated on five (one for each room) separate annunciators in the control room. Each annunciator alarms at a setpoint of 6 inches above the room's floor level. These annunciators are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned 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.

(continued)

BASES (continued)

ACTIONS

Note 1 has been added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to diagnose an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

A Note has also 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 inoperable functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

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 channel, 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 actions in accordance with Specification 5.6.4, which requires a written report to be submitted to the NRC. This

(continued)

BASES

ACTIONS

B.1 (continued)

report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This Required Action is appropriate in lieu of a shutdown requirement since another OPERABLE channel is monitoring the Function, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two or more required channels that are inoperable (i.e., two or more channels inoperable in the same Function), all but 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. 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 the 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.

(continued)

BASES

ACTIONS
(continued)

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C is not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant condition 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 5.6.4. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1.

The Surveillances are modified by a second 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 required channel(s) in the associated Function are 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. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.3.1.1

Performance of a CHANNEL CHECK once every 12 hours is the qualitative assessment, by observation, of channel behavior during operation. This assessment is the comparison, where possible, of the channel status or indication to the status or indication of an independent instrument measuring the same parameter. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A significant deviation could indicate gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar plant instruments located throughout the plant.

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 sensor or the signal processing equipment has drifted outside its limit.

The Frequency of 31 days 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 any 31 day 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 channels required by the LCO.

SR 3.3.3.1.2 and SR 3.3.3.1.3

A CHANNEL CALIBRATION is performed every 18 months for Functions 1, 2, 4, 5, and 10, and every 24 months for Functions 3, 6, and 7. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. For Function 6, the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.3.1.2 and SR 3.3.3.1.3

CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, excluding the detector, for range decades ≥ 10 R/hour and a one point calibration check of the detector with an installed or portable gamma source for range decades < 10 R/hour. The 92 day, 18 month, and 24 month Frequencies are based on operating experience and engineering judgment.

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2, December 1980.
 2. NRC Safety Evaluation Report, "Washington Public Power Supply System, Nuclear Project No. 2, Conformance to Regulatory Guide 1.97," dated March 23, 1988.
 3. 10 CFR 50.36(c)(2)(ii).
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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. At Columbia Generating Station, the remote shutdown system is comprised of the remote shutdown panel (preferred) and the alternate remote shutdown panel. The preferred panel uses the Residual Heat Removal System loop B (RHR B) while the alternate panel uses RHR A. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the Reactor Core Isolation Cooling (RCIC) System, the safety/relief valves, and the Residual Heat Removal System can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the RCIC System and the ability to operate shutdown cooling from outside the control room allow extended operation in MODE 3.

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. 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 an extended 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

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it meets Criterion 4 of Reference 2.

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 controls required are listed in Reference 3.

The controls, instrumentation, and transfer switches are those required for:

- Reactor pressure vessel (RPV) pressure control;
- Decay heat removal;
- RPV inventory control; and
- Standby Service Water System.

The Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown function are OPERABLE. In some cases, the required information or control capability may be available from several alternate sources. In these cases, the Remote Shutdown System is OPERABLE as long as one channel of any of the alternate information or control sources for each Function is OPERABLE.

The Remote Shutdown System instruments and 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 control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

(continued)

BASES (continued)

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 an extended 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 LCO does 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.

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 Function listed in Reference 3, as well as the control and transfer switches.

(continued)

BASES

ACTIONS

A.1 (continued)

The Required Action is to restore the Function (both divisions, if applicable) 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

The Surveillances are modified by a Note to indicate that when an instrument 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. 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. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly operating the associated equipment, when necessary.

SR 3.3.3.2.1

Performance of the CHANNEL CHECK once every 31 days 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

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.3.2.1 (continued)

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 sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency is based upon plant operating experience that demonstrates channel failure is rare.

SR 3.3.3.2.2 and SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy.

The 18 month Frequency of SR 3.3.3.2.2 is based upon operating experience and is consistent with the typical industry refueling cycle. The 24 month Frequency of SR 3.3.3.2.3 is based upon operating experience and engineering judgment.

SR 3.3.3.2.4

SR 3.3.3.2.4 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote and alternate shutdown panels, as appropriate. Operation of the equipment from the remote shutdown panel or alternate 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 or alternate shutdown panels. The 24 month Frequency

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.3.2.4 (continued)

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 demonstrates that Remote Shutdown System controls usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
 2. 10 CFR 50.36(c)(2)(ii).
 3. Licensee Controlled Specifications Manual.
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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 the core thermal M CPR Safety Limit (SL).

The need for the additional negative reactivity in excess of that normally inserted on a scram reflects end of cycle reactivity considerations. Flux shapes at the end of cycle are such that 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 Governor Valve (TGV) Fast Closure, Trip Oil Pressure-Low, or Turbine Throttle Valve (TTV)-Closure. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity at a faster rate than the control rods can add negative reactivity.

The EOC-RPT instrumentation as described in Reference 1 is comprised of sensors that detect initiation of closure of the TTVs, or fast closure of the TGVs, combined with relays, logic circuits, and fast acting circuit breakers that interrupt the power to each of the recirculation pump motors. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs an EOC-RPT signal to the trip logic. When the drive motor 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.

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TTV-Closure or two TGV 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 drive motor breakers in series per recirculation pump. One trip

(continued)

BASES

BACKGROUND
(continued)

system trips one of the two drive motor breakers for each recirculation pump and the second trip system trips the other drive motor breaker for each recirculation pump.

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

The TTV-Closure and the TGV 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 assume EOC-RPT, are summarized in References 2 and 3.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of initial closure movement of either the TTVs or the TGVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does 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 THERMAL POWER, as sensed by turbine first stage pressure, is < 30% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of Reference 4.

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 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. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

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., TGV digital-electro hydraulic (DEH) pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

The specific Applicable Safety Analysis, LCO, and Applicability discussions are listed below on a Function by Function basis.

Alternately, 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 condition EOC-RPT inoperable is specified in the COLR.

Turbine Throttle Valve-Closure

Closure of the TTVs 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 TTV-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 the MCPR SL is not exceeded during the worst case transient.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

Turbine Throttle Valve-Closure (continued)

Closure of the TTVs is determined by measuring the position of each throttle valve. While there are two separate position switches associated with each throttle valve, only the signal from one switch for each TTV is used, with each of the four channels being assigned to a separate trip channel. The logic for the TTV-Closure Function is such that two or more TTVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER \geq 30% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function. Four channels of TTV-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 TTV-Closure Allowable Value is selected to detect imminent TTV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is \geq 30% RTP. Below 30% 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.

TGV Fast Closure, Trip Oil Pressure-Low

Fast closure of the TGVs 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 TGV 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 TGVs is determined by measuring the DEH fluid pressure at each control valve. There is one pressure switch associated with each control valve, and the signal from each switch is assigned to a separate trip channel. The logic for the TGV Fast Closure, Trip Oil Pressure-Low Function is such that two or more TGVs must be closed

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

TGV Fast Closure, Trip Oil Pressure - Low (continued)

(pressure switch trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER \geq 30% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function. Four channels of TGV 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 TGV Fast Closure, Trip Oil Pressure - Low Allowable Value is selected high enough to detect imminent TGV fast closure.

This protection is required consistent with the analysis, whenever the THERMAL POWER is \geq 30% RTP. Below 30% 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. The turbine first stage pressure/reactor power relationship for the setpoint of the automatic enable is identical to that described for TTV closure.

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.

(continued)

BASES

ACTIONS
(continued)A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Action 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 allowed to restore the inoperable channels (Required Action A.1) or apply the EOC-RPT inoperable MCPR limit. 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 in Required Action A.2, 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

channels of the Function, in the same trip system, to each be OPERABLE or in trip, and the associated drive motor breakers to be OPERABLE or in trip. Alternatively, 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 for the operator to take corrective action, 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. Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 30% 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 < 30% 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. 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 recirculation pumps will trip when necessary.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

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. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on reliability analysis (Ref. 5).

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 Frequency for SR 3.3.4.1.2.b is based upon the assumption of an 18 month calibration interval, in the determination of the magnitude of equipment drift in the setpoint analysis.

A Frequency of 24 months is assumed for SR 3.3.4.1.2.a because the TTV position switches are not susceptible to instrument drift.

SR 3.3.4.1.3

This SR ensures that an EOC-RPT initiated from the TTV-Closure and TGV Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq 30\%$ 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 can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER $\geq 30\%$ RTP to ensure that the calibration is valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.4.1.3 (continued)

are bypassed at $\geq 30\%$ RTP either due to open main turbine bypass valves or other reasons), the affected TTV-Closure and TGV 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 considered OPERABLE.

The Frequency of 18 months is based on engineering judgement and reliability of the components.

SR 3.3.4.1.4

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 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 would also be inoperable.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month Frequency.

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 accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 6.

A Note to the Surveillance states that breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. This is allowed since the arc

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.4.1.5 (continued)

suppression time is short and does not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, the 24 month Frequency is consistent with the 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.

SR 3.3.4.1.6

This SR ensures that the RPT breaker arc suppression time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. The 60 month Frequency of the testing is based on the difficulty of performing the test and the reliability of the circuit breakers.

REFERENCES

1. FSAR, Section 7.6.1.5.
 2. FSAR, Section 5.2.2.
 3. FSAR, Sections 15.2.2, 15.2.3, 15.2.5, and 15.2.6.
 4. 10 CFR 50.36(c)(2)(ii).
 5. GENE-770-06-1-A, "Bases for Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," December 1992.
 6. Licensee Controlled Specifications Manual.
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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 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. When Reactor Vessel Water Level-Low Low, Level 2 or Reactor Vessel 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 a recirculation pump trip. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure-High and two channels of Reactor Vessel Water Level-Low Low, Level 2, 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, Level 2 or two Reactor Vessel Steam Dome 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 one trip system trips one recirculation pump (by tripping one of the respective drive motor breakers) while the other trip system trips the other recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ATWS-RPT is not assumed in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation meets Criterion 4 of Reference 2.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

The OPERABILITY of the ATWS-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 3.3.4.2.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump drive motor breaker.

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 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., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the analysis. The Allowable Values are derived from the analytic limits corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

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 Vessel Steam Dome Pressure-High and Reactor Vessel Water Level-Low Low, Level 2 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

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

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 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, Level 2

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 Level 2 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 differential pressure 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 Level - Low Low, Level 2, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel Water Level - Low Low, Level 2, Allowable Value is chosen so that the system will not initiate after a Level 3 scram with feedwater still available, and for convenience with the reactor core isolation cooling (RCIC) initiation.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

b. Reactor Vessel 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 RPV overpressurization. The Reactor Vessel 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 (SRVs), limits the peak RPV pressure to less than the ASME Section III Code Service Level C limits (1500 psig).

The Reactor Vessel Steam Dome Pressure-High signals are initiated from four pressure switches that monitor reactor steam dome pressure. Four channels of Reactor Vessel Steam Dome Pressure-High, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel 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.

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.

(continued)

BASES

ACTIONS
 (continued)

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT trip capability for each Function maintained (refer to Required Action B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function for one of the recirculation pumps. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function for both of the recirculation pumps. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. 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 ATWS-RPT, 7 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel 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 desirable to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D 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 the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and one recirculation pump can

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BASES

ACTIONS

B.1 (continued)

be tripped. This requires two channels of the Function in the same trip system to each be OPERABLE or in trip, and the associated drive motor breaker to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and the fact that one Function is still maintaining ATWS-RPT trip capability.

C.1

Required Action C.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. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action B.1, above.

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.

D.1 and D.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 6 hours (Required Action D.2). Alternately, the associated recirculation pump may be removed from service since this performs the intended Function of the instrumentation (Required Action D.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove a recirculation pump from service in an orderly manner and without challenging plant systems.

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BASES (continued)

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 ATWS-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. 3) 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 3.3.4.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that 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 that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

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. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 3.

SR 3.3.4.2.3

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 Frequency is based upon the assumption of an 18 month calibration interval in the determination of 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, included as part of this Surveillance, 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

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BASES (continued)

REFERENCES

1. FSAR, Section 15.8.
 2. 10 CFR 50.36(c)(2)(ii).
 3. GENE-770-06-1-A, "Bases For Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," December 1992.
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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 fuel is adequately cooled in the event of a design basis accident or transient.

For most anticipated operational occurrences (A00s) and Design Basis Accidents (DBAs), a wide range of dependent and independent parameters are monitored.

The ECCS instrumentation actuates low pressure core spray (LPCS), low pressure coolant injection (LPCI), high pressure core spray (HPCS), 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."

Low Pressure Core Spray System

The LPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level-Low Low Low, Level 1 or Drywell Pressure-High. Reactor vessel water level is monitored by two redundant differential pressure switches and drywell pressure is monitored by two redundant pressure switches, which are, in turn, connected to two level switch and two pressure switch contacts, respectively. The outputs of the four switches (two switches from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The LPCS initiation signal is a sealed-in signal and must be manually reset. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. Upon receipt of an initiation signal, the LPCS pump is automatically started in approximately 9.5 seconds if normal AC power (from TR-S) is available; otherwise the pump is started immediately after AC power (from TR-B or the DG) is available.

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BASES

BACKGROUND

Low Pressure Core Spray System (continued)

The LPCS test line isolation valve, which is also a primary containment isolation valve (PCIV), is closed on a LPCS initiation signal to allow full system flow assumed in the accident analysis and to maintain containment isolation in the event LPCS is not operating.

The LPCS pump discharge flow is monitored by a flow indicating switch. When the pump is running and discharge flow is low enough 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 full system flow assumed in the accident analysis.

The LPCS System also monitors the pressure in the reactor vessel to ensure that, before the injection valve opens, the reactor pressure has fallen to a value below the LPCS Systems maximum design pressure. The variable is monitored by one pressure switch whose contact is arranged in a one-out-of-one logic.

Low Pressure Coolant Injection Subsystems

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with three LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High. Reactor vessel water level is monitored by two redundant differential pressure switches per division and drywell pressure is monitored by two redundant pressure switches per division, which are, in turn, connected to two level switch and two pressure switch contacts, respectively. The outputs of the four Division 2 LPCI (loops B and C) switches (two switches from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its initiation signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic. The two divisions can also be initiated by use of a manual switch and push button (one per division, with the LPCI A manual switch and push button being common with LPCS), whose two contacts are

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BASES

BACKGROUND

Low Pressure Coolant Injection Subsystem (continued)

arranged in a two-out-of-two logic. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

Upon receipt of an initiation signal, each LPCI pump is automatically started, (LPCI Pump C in approximately 9.5 seconds and LPCI Pumps A and B in approximately 19.4 seconds if normal AC power (from TR-S) is available; otherwise LPCI Pump C is started immediately after AC power (from TR-B or the DG) is available while LPCI Pumps A and B are started after a 5 second delay), to limit the loading on the normal and standby power sources.

Each LPCI subsystems discharge flow is monitored by a flow indicating switch. When a pump is running and discharge flow is low enough that pump overheating may occur, the respective minimum flow return line valve is opened after approximately 8 seconds. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the analyses.

The RHR test line suppression pool cooling and spray isolation valves, which are also PCIVs, are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and to maintain containment isolated in the event LPCI is not operating.

The LPCI subsystems monitor the pressure in the reactor vessel to ensure that, prior to an injection valve opening, the reactor pressure has fallen to a value below the LPCI subsystems maximum design pressure. The variable is monitored by three redundant switches (one per valve), whose contacts are arranged in a one-out-of-one logic for each valve.

High Pressure Core Spray System

The HPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High. Reactor vessel water level is monitored by four redundant differential pressure switches and drywell

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High Pressure Core Spray System (continued)

pressure is monitored by four redundant pressure switches. The outputs of the switches are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each variable. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. The HPCS System initiation signal is a sealed in signal and must be manually reset.

The HPCS pump discharge flow is monitored by a flow switch. When the pump is running and discharge flow is low enough 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 full system flow assumed in the accident analyses.

The HPCS test line isolation valves, of which the suppression pool test line isolation valve is also a PCIV, are closed on a HPCS initiation signal to allow full system flow assumed in the accident analyses and to maintain containment isolated in the event HPCS is not operating.

The HPCS System also monitors the water levels in the condensate storage tanks (CST) and the suppression pool, since these are the two sources of water for HPCS operation. Reactor grade water in the CST is the normal and preferred source. Upon receipt of a HPCS initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position), unless the suppression pool suction valve is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens, 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 valve to open and the CST suction valve to close (one-out-of-two logic). The suppression pool suction valve also automatically opens and the CST suction valve closes if high water level is detected in the suppression pool. Two level switches are also used to detect high suppression pool water level, with a

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High Pressure Core Spray System (continued)

one-out-of-two logic similar to the CST water level logic. 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 HPCS System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip, at which time the HPCS injection valve closes. The HPCS pump will continue to run on minimum flow. The logic is two-out-of-two to provide high reliability of the HPCS System. The injection valve automatically reopens if a low low water level signal is subsequently received.

Automatic Depressurization System

ADS may be initiated by either automatic or manual means. Automatic initiation occurs when signals indicating Reactor Vessel Water Level-Low Low Low, Level 1; confirmed Reactor Vessel Water Level-Low, Level 3; and either LPCS or LPCI Pump Discharge Pressure-High are all present, and the ADS Initiation Timer has timed out. There are two differential pressure switches for Reactor Vessel Water Level-Low Low Low, Level 1 and one differential pressure switch for confirmed Reactor Vessel Water Level-Low, Level 3 in each of the two ADS trip systems. Each of these differential pressure switches connects to a level switch, which then drives a relay whose contacts form the initiation logic.

Each ADS trip system (trip system A and trip system B) includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The time delay chosen is long enough that the HPCS has time to operate to recover to a level above Level 1, yet not so long that the LPCI and LPCS systems are unable to adequately cool the fuel if the HPCS fails to maintain level. An alarm in the control room is annunciated when either of the timers is running. Resetting the ADS initiation signals resets the ADS Initiation Timers.

The ADS also monitors the discharge pressures of the three LPCI pumps and the LPCS pump. Each ADS trip system includes two discharge pressure permissive switches from each of the two low pressure ECCS pumps in the associated Division

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Automatic Depressurization System (continued)

(i.e., Division 1 ECCS inputs to ADS trip system A and Division 2 ECCS inputs to ADS trip system 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 four low pressure pumps provides sufficient core coolant flow to permit automatic depressurization.

The ADS logic in each trip system is arranged in two strings. One string has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3; ADS Initiation Timer; and two low pressure ECCS Discharge Pressure—High contacts (one from each divisional pump). The other string has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1; and two low pressure ECCS Discharge Pressure—High contacts (one from each divisional pump). To initiate an ADS trip system, the following applicable contacts must close in the associated string: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3 (one string only); ADS Initiation Timer; and one of the two low pressure ECCS Discharge Pressure—High contacts.

Either ADS trip system A or trip system B will cause all the ADS relief valves to open. Once an ADS trip system is initiated, it is sealed in until manually reset.

Manual initiation for each trip system is accomplished by use of two manual switches and push buttons, whose four contacts (two per manual switch and push button) are arranged in a four-out-of-four logic (two contacts per ADS logic string). Manual inhibit switches are provided in the control room for ADS; however, their function is not required for ADS OPERABILITY (provided ADS is not inhibited when required to be OPERABLE).

In addition to the ADS initiation instrumentation, the ADS accumulator backup compressed gas system is automatically aligned when the normal, non-safety related nitrogen supply pressure is low to ensure a safety related supply of air is

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Automatic Depressurization System (continued)

provided to the ADS valves during post LOCA conditions. Each subsystem is actuated when two of the three pressure signals (one pressure signal closes the normal air supply valve, which then sends the trip signal) indicate a low ADS air header pressure.

Diesel Generators

The Division 1, 2, and 3 DGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low Low, Level 1 or Drywell Pressure - High for DGs 1 and 2, and Reactor Vessel Water Level - Low Low, Level 2 or Drywell Pressure - High for DG 3. The DGs are also initiated upon loss of voltage signals. (Refer to Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) Reactor vessel water level is monitored by two redundant differential pressure switches and drywell pressure is monitored by two redundant pressure switches per DG, which are, in turn, connected to two level switch and two pressure switch contacts, respectively. The outputs of the four divisionalized switches (two switches from each of the two variables) are connected to relays whose contacts are connected to a one-out-of-two taken twice logic. The DGs receive their initiation signals from the associated Divisions' ECCS logic (i.e., DG 1 receives an initiation signal from Division 1 ECCS (LPCS and LPCI A); DG 2 receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C); and DG 3 receives an initiation signal from Division 3 ECCS (HPCS)). The DGs can also be started manually from the control room and locally in the associated DG room. The DG initiation signal is a sealed in signal and must be manually reset. The DG initiation logic is reset by resetting the associated ECCS initiation logic. Upon receipt of an ECCS initiation signal, each DG is automatically started, is ready to load in approximately 15 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 (ESF) buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1).

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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 Reference 4. 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 and 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. Each ECCS injection/spray subsystem must also respond within its assumed response time. Table 3.3.5.1-1, footnote (b), is added to show that certain ECCS instrumentation Functions are also required to be OPERABLE to 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 water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived

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in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account. Some functions have both an upper and lower analytic limit that must be evaluated. The Allowable Values and the trip setpoints are derived from both an upper and lower analytic limit using the methodology described above. Due to the upper and lower analytic limits, Allowable Values of these Functions appear to incorporate a range. However, the upper and lower Allowable Values are unique, with each Allowable Value associated with one unique analytic limit and trip setpoint.

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 a design basis accident or transient. 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.

Low Pressure Core Spray and Low Pressure Coolant Injection Systems1.a, 2.a. Reactor Vessel Water Level - Low Low Low, Level 1

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 Level 1 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 1, 2, and 3. In addition, the Reactor Vessel Water Level - Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break (Refs. 1, 2, and 3). 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.

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SAFETY ANALYSES,
LCO, and
APPLICABILITY1.a, 2.a. Reactor Vessel Water Level - Low Low Low, Level 1
(continued)

Reactor Vessel Water Level - Low Low Low, Level 1 signals are initiated from four differential pressure 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, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling.

Two channels of Reactor Vessel Water Level - Low Low Low, Level 1 Function per associated Division are only required to be OPERABLE when the associated ECCS or DG is required to be OPERABLE, to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and DG 1, while the other two channels input to LPCI B, LPCI C, and DG 2.) Refer to LCO 3.5.1 and LCO 3.5.2, "ECCS - Shutdown," for Applicability Bases for the low pressure ECCS subsystems; LCO 3.8.1, "AC Sources - Operating"; and LCO 3.8.2, "AC Sources - Shutdown," for Applicability Bases for the DGs.

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. However, no credit is taken for the Drywell Pressure - High Function to start the low pressure ECCS in any design basis accident or transient analyses. It is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis. 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.

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1.b, 2.b. Drywell Pressure-High (continued)

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. Negative barometric fluctuations are accounted for in the Allowable Value.

The Drywell Pressure-High Function is required to be OPERABLE when the associated ECCS and DGs are required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the LPCS and LPCI Drywell Pressure-High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and DG 1, while the other two channels input to LPCI B, LPCI C, and DG 2.) 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, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and C Start-LOCA Time Delay Relay and LPCI Pumps A and B Start-LOCA/LOOP Time Delay Relay

The purpose of these time delays is to stagger the start of the ECCS pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV emergency buses. The LOCA Time Delay Relay Function is only necessary when the power is being supplied from the TR-S transformer, and the LOCA/LOOP Time Delay Relay Function is only necessary when power is being supplied from the standby power sources (DG). However, since the LOCA/LOOP time delay does not degrade ECCS operation, it remains in the pump start logic at all times. The Pump Start-LOCA and LOCA/LOOP Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analysis assumes that the pumps will initiate when required and excess loading will not cause failure of the power sources due to a degraded voltage condition (see Table 3.3.8.1-1).

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1.c, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and C Start-LOCA Time Delay Relay and LPCI Pumps A and B Start-LOCA/LOOP Time Delay Relay (continued)

There are four Pump Start-LOCA Time Delay Relay channels, one in each of the low pressure ECCS pump start logic circuits. Each of the LOCA Time Delay Relay channels consists of a Drywell Pressure-High and Reactor Level 2 sensor, auxiliary relay logic, and circuit breaker position switches to initiate the LOCA time delay relay when on TR-S. The LOCA Time Delay Relay channel sensors also provide Drywell Pressure-High RPS Trip (Table 3.3.1.1-1 Function 6) and Drywell Pressure/Level 2 Primary Containment and RWCU Isolation (Table 3.3.6.1-1 Functions 2.b, 2.c, and 4.j) and Secondary Containment Isolation (Table 3.3.6.2-1 Functions 1 and 2) channel signals. A Drywell Pressure-High and a Level 2 sensor are in series and deenergize (either instrument) to initiate a LOCA Time Delay Relay channel. Two LOCA Time Delay Relay channels are provided for each division low pressure ECCS Function. Initiation of one LOCA Time Delay Relay channel will result in the other LOCA Time Delay Relay channel in the division initiating simultaneously to assure a nominal 9.9 second difference in low pressure ECCS subsystem starts within each ECCS function (LPCS/LPCI-C are set at 9.5 seconds and LPCI-A/LPCI-B are set at 19.4 seconds with appropriate allowable values.) While each channel is dedicated to a single pump start logic, a single failure of an instrument sensor or logic relay could potentially result in failure of the offsite 230 kV supply. One low pressure ECCS pump on either ESF bus could start simultaneously with the HPCS pump followed shortly by a second low pressure ECCS pump start while powered from the 230 kV offsite supply and potentially trip the 230 kV circuit supply to both ESF buses and HPCS. The transfer would occur due to degraded voltage relay operation. If loss of the 230 kV source occurs, transfer to the 115 kV or DGs will occur within the ECCS RESPONSE TIME (for MODE 1, 2, or 3). Thus, single failure criteria is met for this condition. However, the supported ECCS features are impacted and appropriate Actions and Completion Times have been established in LCO 3.3.5.1, Action C. Additionally, the 230 kV offsite supply is a supported feature by the LOCA Time Delay Relay channels for use in meeting LCO 3.8.1 or

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1.c, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and
 C Start-LOCA Time Delay Relay and LPCI Pumps A and B
 Start-LOCA/LOOP Time Delay Relay (continued)

LCO 3.8.2. A Note (e) has been provided to Table 3.3.5.1-1 that identifies Functions 1c, 1d, 2c, and 2d as supporting OPERABILITY of the 230 kV offsite power source. This assumes HPCS or the low pressure ECCS pumps on the affected division are not disabled to prevent automatic loading. In MODE 4 or 5, when HPCS is not being relied upon to meet LCO 3.5.2 (i.e., disabled), LCO 3.8.2 should not be affected. Use of the Safety Function Determination Program (TS 5.5.11) provides the means for AC Sources OPERABILITY determination.

There are two pump Start-LOCA/LOOP Time Delay Relay channels, one in each of the RHR "A" and RHR "B" pump start logic circuits. The LOCA/LOOP Time Delay Relay channels consist of Level 1 and Drywell Pressure-High sensors (Table 3.3.5.1-1 Functions 1.a, 1.b, 2.a, and 2.b), auxiliary relay logic, circuit breaker position switches and power available relays. While each time delay is dedicated to a single pump start logic, a single failure of a Pump Start LOCA/LOOP Time Delay Relay could result in the failure of the two low pressure ECCS pumps, powered from the same ESF bus, to perform their intended function within the assumed ECCS RESPONSE TIMES (MODE 1, 2, or 3). In this case, both ECCS pumps on one ESF bus could start simultaneously when powered by the associated onsite DG due to an inoperable LOCA/LOOP time delay relay and cause loss of the ESF bus. In the case of simultaneous starts of both ECCS pumps on a DG, this still leaves two of the four low pressure ECCS pumps OPERABLE; thus, single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation within the ECCS RESPONSE TIME requirements).

The Allowable Values for the Pump Start-LOCA and LOCA/LOOP Time Delay Relay channels are chosen to be long enough so that most of the starting transient of the first pump is complete before starting the second pump on the same 4.16 kV emergency bus, and short enough so that ECCS operation is not degraded. Appropriate Actions and Completion Times are specified to limit the time a LOCA or a LOCA/LOOP Time Delay Relay channel can be inoperable.

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1.c, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and
C Start-LOCA Time Delay Relay and LPCI Pumps A and B
Start-LOCA/LOOP Time Delay Relay (continued)

Note (a) is added to show that the required ECCS instrumentation Functions should be OPERABLE in MODES 4 and 5 "when associated subsystem(s) are required to be OPERABLE." Each required channel of the Pump Start LOCA Time Delay Relay Function is only required to be OPERABLE when the associated ECCS subsystem(s) are required to be OPERABLE. In MODES 4 and 5 with HPCS not being relied upon for LCO 3.5.2, the associated time delay function of the channel is not required to be OPERABLE provided automatic initiation of the required low pressure ECCS subsystem(s) to Reactor Vessel Water Level - Low Low Low, Level 1 is maintained. The LOCA/LOOP Time Delay Relay function is only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE.

Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the LPCI subsystems.

Only the Reactor Vessel Water - Low Low, Level 2 (Function 2b LCO Table 3.3.6.1-1) is required for input to the LOCA Time Delay Relay Channels. The Drywell Pressure-High Function is not required for input to the LOCA and LOCA/LOOP Time Delay Relay Channels since there is insufficient energy in the reactor to pressurize the primary containment to Drywell Pressure-High setpoint.

1.f, 2.f. Reactor Vessel Pressure-Low (Injection
Permissive)

Low reactor vessel 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 Vessel 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 1, 2, and 3. In addition, the Reactor Vessel Pressure-Low Function is directly assumed in the analysis of the

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1.f, 2.f. Reactor Vessel Pressure-Low (Injection
Permissive) (continued)

recirculation line break (Refs. 1, 2, and 3). 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 Vessel Pressure-Low signals are initiated from four pressure switches that sense the reactor dome pressure (one pressure switch for each low pressure ECCS injection valve).

The Allowable Value is low enough to prevent overpressurizing 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.

Each channel of Reactor Vessel Pressure-Low Function (one per valve) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.g, 1.h, 2.g. LPCS and LPCI Pump Discharge Flow-Low
(Minimum Flow)

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 sufficiently 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 LPCI and LPCS 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 flows 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.

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1.g, 1.h, 2.g. LPCS and LPCI Pump Discharge Flow-Low
(Minimum Flow) (continued)

One flow indicating switch per ECCS pump is used to detect the associated subsystem's flow rate. The logic is arranged such that each indicating switch causes its associated minimum flow valve to open when flow is low with the pump running. 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 8 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the 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.

Each channel of Pump Discharge Flow-Low Function (one LPCS channel and three LPCI channels) 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 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.i, 2.h. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There is one switch and push button (with two channels per switch and push button) for each of the two Divisions of low pressure ECCS (i.e., Division 1 ECCS, LPCS and LPCI A; Division 2 ECCS, LPCI B and LPCI C).

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis.

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3.a. Reactor Vessel Water Level - Low Low, Level 2
(continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Each channel of the Manual Initiation Function (two channels per Division) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

High Pressure Core Spray System

3.a. Reactor Vessel Water Level - Low Low, Level 2

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 HPCS System and associated DG is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level - Low Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCS during the transients analyzed in References 1, 2, and 3. The Reactor Vessel Water Level - Low Low, Level 2 Function associated with HPCS is directly assumed in the analysis of the recirculation line break (Refs. 1, 2, and 3). 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, Level 2 signals are initiated from four differential pressure 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, Level 2 Allowable Value is chosen such that for complete loss of feedwater flow, the Reactor Core Isolation Cooling (RCIC) System flow with HPCS assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level - Low Low, Level 1.

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3.a. Reactor Vessel Water Level - Low Low, Level 2
(continued)

Four channels of Reactor Vessel Water Level - Low Low, Level 2 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.b. Drywell Pressure - High

High pressure in the drywell could indicate a break in the RCPB. The HPCS System and associated DG are initiated upon receipt of the Drywell Pressure - High Function in order to minimize the possibility of fuel damage. However, no credit is taken for the Drywell Pressure - High Function to start the HPCS System in any DBA or transient analyses; that is, HPCS is assumed to be initiated on Reactor Water Level - Low Low, Level 2. It is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis. 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.

Drywell Pressure - High 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.

The Drywell Pressure - High Function is required to be OPERABLE when HPCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the HPCS Drywell Pressure - High Function are required to be OPERABLE in MODES 1, 2, and 3, to ensure that no single instrument failure can preclude ECCS 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 drywell to the Drywell Pressure - High Function's setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

(continued)

BASES

APPLICABLE
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LCO, and
APPLICABILITY
(continued)

3.c Reactor Vessel Water Level-High, Level 8

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 Level 8 signal is used to close the HPCS injection valve to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level-High, Level 8 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 Reference 4.

Reactor Vessel Water Level-High, Level 8 signals for HPCS are initiated from two differential pressure switches from the narrow range water level measurement instrumentation. The Reactor Vessel Water Level-High, Level 8 Allowable Value is chosen to isolate flow from the HPCS System prior to water overflowing into the MSLs. Two channels of Reactor Vessel Water Level-High, Level 8 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.d. Condensate Storage Tank Level-Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCS and the CST are open and, upon receiving a HPCS initiation signal, water for HPCS 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 valve automatically opens, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCS pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve 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 HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

(continued)

BASES

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3.d. Condensate Storage Tank Level - Low (continued)

Condensate Storage Tank Level - Low signals are initiated from two level switches mounted on a Seismic Category I standpipe in the reactor building (the two switches mounted on the CST cannot be credited since they are not Seismic Category I). 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 only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. Thus, the Function is required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the Function is required to be OPERABLE only when HPCS is required to be OPERABLE to fulfill the requirements of LCO 3.5.2, HPCS is aligned to the CST, and the CST water level is not within the limits of SR 3.5.2.2. With CST water level within limits, a sufficient supply of water exists for injection to minimize the consequences of a vessel draindown event. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS 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 SRVs. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCS from the CST to the suppression pool to eliminate the possibility of HPCS continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve 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 HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

(continued)

BASES

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3.e. Suppression Pool Water Level-High (continued)

Suppression Pool Water Level-High signals are initiated from two level switches. The Allowable Value for the Suppression Pool Water Level-High Function is chosen to ensure that HPCS 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 only required to be OPERABLE in MODES 1, 2, and 3 when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. In MODES 4 and 5, the Function is not required to be OPERABLE since the reactor is depressurized and vessel blowdown, which could cause the design values of the containment to be exceeded, cannot occur. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.f. HPCS System Flow Rate-Low (Minimum Flow)

The minimum flow instrument is provided to protect the HPCS pump from overheating when the pump is operating and the associated injection valve is not sufficiently 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 HPCS System Flow Rate-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 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 is used to detect the HPCS Systems flow rate. The logic is arranged such that the flow switch causes the minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded.

(continued)

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3.f. HPCS System Flow Rate-Low (Minimum Flow) (continued)

The HPCS System Flow Rate-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 full flow into the core.

One channel of HPCS System Flow Rate-Low Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.g. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one switch and push button (with two channels) for the HPCS System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of the Manual Initiation Function are only required to be OPERABLE when the HPCS System are required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level-Low Low Low, Level 1

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

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4.a, 5.a. Reactor Vessel Water Level - Low Low Low, Level 1
(continued)

Function. The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accidents analyzed in References 1, 2, and 3. 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 Vessel Water Level - Low Low Low, Level 1 signals are initiated from four differential pressure 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, Level 1 Allowable Value is chosen to allow time for the low pressure core spray and flooding systems to initiate and provide adequate cooling.

Four channels of Reactor Vessel Water Level - Low Low Low, Level 1 Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Two channels input to ADS trip system A while the other two channels input to ADS trip system B). Refer to LCO 3.5.1 for ADS Applicability Bases.

4.b, 5.b. ADS Initiation Timer

The purpose of the ADS Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCS 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 HPCS System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the

(continued)

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4.b, 5.b. ADS Initiation Timer (continued)

timer, or to inhibit initiation permanently. The ADS Initiation Timer Function is assumed to be OPERABLE for the accident analyses of References 1, 2, and 3 that require ECCS initiation and assume failure of the HPCS System.

There are two ADS Initiation Timer relays, one in each of the two ADS trip systems. The Allowable Value for the ADS Initiation Timer is chosen to be short enough so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

4.c, 5.c. Reactor Vessel Water Level—Low, Level 3 (Permissive)

Two channels of the ADS Initiation 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 system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases. The Reactor Vessel Water Level—Low, Level 3 Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level—Low Low Low, Level 1 signals. In order to prevent spurious initiation of the ADS due to spurious Level 1 signals, a Level 3 signal must also be received before ADS initiation commences.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from two differential pressure 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, Level 3 is selected at the RPS Level 3 scram Allowable Value for convenience. Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for Bases discussion of this Function.

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4.c, 5.c. Reactor Vessel Water Level - Low, Level 3
(Permissive) (continued)

Two channels of Reactor Vessel Water Level - Low, Level 3 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 system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d. LPCS and LPCI Pump Discharge Pressure - High

The Pump Discharge Pressure - High signals (indicating that the pump is running) from the LPCS 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 References 1, 2, and 3 with an assumed HPCS 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 eight pressure switches, two on the discharge side of each of the four low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure - High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode, and high enough to avoid any condition that results in a discharge pressure permissive when the LPCS 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.

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4.d, 4.e, 5.d. LPCS and LPCI Pump Discharge Pressure—High
(continued)

Eight channels of LPCS and LPCI Pump Discharge Pressure—High Function (two LPCS and two LPCI A channels input to ADS trip system A, while two LPCI B and two LPCI C channels input to ADS trip system B) 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. Refer to LCO 3.5.1 for ADS Applicability Bases.

4.f, 5.e. Accumulator Backup Compressed Gas System Pressure—Low

The purpose of the Accumulator Backup Compressed Gas System Pressure—Low Function is to ensure that a safety related supply of air is available to the ADS valves during post LOCA conditions. The normal air supply to the ADS valves is non-safety related and may not be available following a LOCA. If the normal air supply pressure is low, the Accumulator Backup Compressed Gas System Pressure—Low Function will automatically align the Accumulator Backup Compressed Gas System to provide the necessary air supply to the ADS valves. The Accumulator Backup Compressed Gas System Pressure—Low Function is assumed to be OPERABLE and capable of automatically aligning the Accumulator Backup Compressed Gas System during the accidents analyzed in References 1, 2, and 3.

Accumulator Backup Compressed Gas System Pressure—Low signals are initiated from six pressure switches that sense the ADS air header supply pressure. The Accumulator Backup Compressed Gas System Pressure—Low Allowable Value is chosen to ensure an adequate air supply is available to the ADS valves.

Six channels of Accumulator Backup Compressed Gas System Pressure—Low Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Three channels input to Division 1 Accumulator Backup Compressed Gas subsystem and the other three channels input to Division 2 Accumulator Backup Compressed Gas subsystem.) Refer to LCO 3.5.1 for ADS Applicability Bases.

(continued)

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4.g, 5.f. Manual Initiation (continued)

The Manual Initiation switch and push button channels introduce signals into the ADS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There are two switch and push buttons (with two channels per switch and push button) for each ADS trip system (total of four).

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the ADS function as required by the NRC in the plant licensing basis.

4.g, 5.f. Manual Initiation

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Eight channels of the Manual Initiation Function (four channels per ADS trip system) are only required to be OPERABLE when the ADS is required to be OPERABLE. 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 specified 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, 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 variable 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 feature would be HPCS. For Required Action B.1, redundant automatic initiation capability is lost if either (a) one or more Function 1.a channels and one or more Function 2.a channels are inoperable and untripped, or (b) one or more Function 1.b channels and one or more Function 2.b channels are inoperable and untripped. For Divisions 1 and 2, 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 Division of low pressure ECCS and DG to be declared inoperable. However, since channels in both Divisions are inoperable and untripped, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions of ECCS and DG being concurrently declared inoperable. For Required Action B.2, redundant automatic initiation capability is lost if two Function 3.a or two Function 3.b channels are inoperable and untripped in the same trip system.

In this situation (loss of redundant 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. As noted (Note 1 to Required Action B.1 and

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

Required Action B.2), the two Required Actions are only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 24 hours (as allowed by Required Action B.3) is allowed during MODES 4 and 5. Notes are also provided (Note 2 to Required Action B.1 and 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.

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 allowed outage time "clock."

For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable, untripped channels within the same variable as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCS System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. 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

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ACTIONS

B.1, B.2, and B.3 (continued)

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 H must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same variable result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, and 2.f (i.e., low pressure ECCS). For Functions 1.c, 1.d, 2.c, and 2.d, redundant automatic initiation capability is lost if the Function 1.c or 1.d channel concurrent with the Function 2.c or 2.d channel are inoperable. For Functions 1.e and 2.e, redundant automatic initiation capability is lost if the Function 1.e and Function 2.e channels are inoperable. For Functions 1.f and 2.f, redundant automatic initiation capability is lost if one Function 1.f channel and one Function 2.f channel are inoperable. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division to be declared inoperable. However, since channels in both Divisions are inoperable, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions being concurrently declared inoperable. For Functions 1.c, 1.d, 2.c, and 2.d, the affected portions of the Divisions are LPCS, LPCI A, LPCI B, and LPCI C, respectively. For Functions 1.e and 2.e, the affected portions of the Division are LPCI A and LPCI B, respectively. For Functions 1.f and 2.f, the affected portions of the Division are the associated low pressure ECCS pumps (Divisions 1 and 2, respectively).

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour. As noted (Note 1), the Required Action is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of automatic initiation capability for 24 hours (as allowed by Required Action C.2) is allowed during MODES 4 and 5.

Note 2 states that Required Action C.1 is only applicable for Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, and 2.f. The Required Action is not applicable to Functions 1.i, 2.h, and 3.g (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed. Required Action C.1 is also 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.2.

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 allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable channels within the same variable 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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 H 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 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 component initiation capability for the HPCS System. Automatic component initiation 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 HPCS System must be declared inoperable within 1 hour after discovery of loss of HPCS initiation capability. As noted, the Required Action is only applicable if the HPCS pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

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 allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCS 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 initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

E.1 and E.2

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

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 Required Action D.2.2 is performed, measures should be taken to ensure that the HPCS 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 HPCS suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the LPCS and LPCI Pump Discharge Flow-Low (Minimum Flow) 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.g, 1.h, and 2.g (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.g, 1.h, and 2.g 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 to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

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BASES

ACTIONS

E.1 and E.2 (continued)

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the feature(s) associated with each inoperable channel must be declared inoperable within 1 hour after discovery of loss of initiation capability for feature(s) in both Divisions. As noted (Note 1 to Required Action E.1), Required Action E.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the low pressure ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 7 days (as allowed by Required Action E.2) is allowed during MODES 4 and 5. A Note is also provided (Note 2 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 HPCS 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.

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 allowed outage time "clock." For Required Action E.1, the Completion Time only begins upon discovery that three channels of the variable (Pump Discharge Flow-Low) cannot be automatically initiated due to inoperable channels. 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 pump flow could be diverted from the reactor injection path, causing insufficient core cooling. These

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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. 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 H 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.

F.1 and F.2

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped 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 or more Function 4.a channel and one or more Function 5.a channel are inoperable and untripped, (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped, or (c) two or more Function 4.f channels and two or more Function 5.e channels are inoperable and untripped.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action F.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems.

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 allowed outage time "clock." For Required Action F.1, the Completion Time only begins

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

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 HPCS and RCIC are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCS 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 F.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 H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

channel and one Function 5.b channel are inoperable, (b) one or more Function 4.d channels and one or more Function 5.d channels are inoperable, or (c) one or more Function 4.e channels and one or more Function 5.d channels are inoperable.

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 in both trip systems. The Note to Required Action G.1 states that Required Action G.1 is only applicable for Functions 4.b, 4.d, 4.e, 5.b, and 5.d. Required Action G.1 is not applicable to Functions 4.g and 5.f (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 96 hours or 8 days (as allowed by Required Action G.2) is allowed.

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 allowed outage time "clock." For Required Action G.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 HPCS and RCIC are OPERABLE (Required Action G.2). If either HPCS or RCIC is inoperable, the time is reduced to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

discovery of HPCS or RCIC inoperability. However, total time for an inoperable channel cannot exceed 8 days. If the status of HPCS 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 service time, Condition H 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.

H.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 the inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE
REQUIREMENTS

As noted at 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 for up to 6 hours as follows: (a) for Functions 3.c, 3.f, and 3.g; and (b) for Functions other than 3.c, 3.f, and 3.g provided the associated Function or redundant Function maintains ECCS 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. 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)

SR 3.3.5.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of Reference 5.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.5.1.3, SR 3.3.5.1.4, and SR 3.3.5.1.5

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. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequencies are based upon the assumption of a 92 day, 18 month, or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

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 provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage (except for Division 3 which can be tested in any operational condition) and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 6.2.
 2. FSAR, Section 6.3.
 3. FSAR, Chapter 15.
 4. 10 CFR 50.36(c)(2)(ii).
 5. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.
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B 3.3 INSTRUMENTATION

B 3.3.5.2 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 insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level 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. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low, Level 2. The variable is monitored by four differential pressure switches. The switch contacts are arranged in a one-out-of-two taken twice logic arrangement. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. 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 line isolation valve is closed on a RCIC initiation signal to allow full system flow.

The RCIC System also monitors the water levels in the condensate storage tanks (CST) since this is the initial source of water for RCIC operation. Reactor grade water in the CST is the normal source. 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 valve from the suppression pool is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens 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 valve to open and the CST suction valve to close (one-out-of-two logic). To prevent losing

(continued)

BASES

BACKGROUND
(continued)

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 high water level (Level 8) trip (two-out-of-two 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 level initiation point (Level 2).

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

The function of the RCIC System, to provide makeup coolant to the reactor, is to respond to transient events. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analysis for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the RCIC System, and therefore its instrumentation, meets Criterion 4 of Reference 1. 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 on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.2-1. 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.

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. The setpoints are compared to the actual process parameter

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

(e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

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, Level 2

Low reactor pressure vessel (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 Level 2 to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level - Low Low, Level 2 signals are initiated from four differential pressure 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, Level 2 Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with high pressure core spray assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Level 1.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

1. Reactor Vessel Water Level - Low Low, Level 2
(continued)

Four channels of Reactor Vessel Water Level - Low Low, Level 2 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, Level 8

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 Level 8 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, Level 8 signals for RCIC are initiated from two differential pressure switches from the narrow range water level measurement instrumentation, which 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, Level 8 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, Level 8 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 normal source. Normally the suction valve between the RCIC pump and the CST is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CST. However, if

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

3. Condensate Storage Tank Level - Low (continued)

the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens 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 valve must be open before the CST suction valve automatically closes.

Two level switches are used to detect low water level in the CST. 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.

4. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the RCIC System initiation logic that is redundant to the automatic protective instrumentation and provides manual initiation capability. There is one switch and push button (with two channels) for the RCIC System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the RCIC function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of Manual Initiation are required to be OPERABLE when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for RCIC Applicability Bases.

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BASES (continued)

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, a Note has been provided that allows separate Condition entry for each inoperable RCIC System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.2-1 in the accompanying LCO. 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 two Function 1 channels in the same trip system 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 allowed outage time "clock."

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level-Low Low, Level 2 channels in the same trip system. 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 or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) 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.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. 2) 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, Level 8 Function, whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability (loss of high water level trip capability). As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any

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BASES

ACTIONS C.1 (continued)

accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in the 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 automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this case, automatic component initiation capability is lost if two Function 3 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 RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation 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.

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 allowed outage 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 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 or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

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 suction 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.

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.

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 4; and (b) for up to 6 hours for Functions 1 and 3 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 OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.5.2.1

Performance of a CHANNEL CHECK once every 12 hours is the qualitative assessment, by observation, of channel behavior during operation. This assessment is the comparison, where possible, of the channel status or indication to the status or indication of an independent instrument measuring the same parameter. 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 significant deviation could indicate gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the 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 channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 2.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.5.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter with 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 Frequency is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).
 2. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications." December 1992.
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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 electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel 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 logic are (a) reactor vessel water level, (b) area and differential temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum loss, (f) main steam line pressure, (g) reactor core isolation cooling (RCIC) steam line flow and time delay relay, (h) ventilation exhaust plenum radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential and blowdown flows and time delay relay, (l) reactor vessel pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. In addition, manual isolation of the logics is provided.

The primary containment isolation instrumentation has inputs to the trip logic from the isolation functions listed below.

(continued)

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BACKGROUND
(continued)

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in 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 trip systems to isolate all MSL drain valves. One two-out-of-two trip system is associated with the inboard valve and the other two-out-of-two logic trip system is associated with the outboard valves.

The exceptions to this arrangement are the Main Steam Line Flow-High and the Manual Initiation Functions. The Main Steam Line Flow-High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of four trip strings. Two trip strings make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two taken twice logic. Therefore, 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 one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Manual Initiation Function uses eight channels, two per each switch and push button. The four channels from two switch and push buttons input into one trip system and the four channels from the other two switch and push buttons input into the other trip system. To close all MSIVs, both trip systems must actuate, similar to all the other Functions described above. However, the logic of each trip system is arranged such that both channels from one of the associated switch and push buttons are required to actuate the trip system (i.e., the switch and push button must be both armed and depressed for the trip system to actuate). To close the MSL drain valves, all channels in both trip systems must actuate (i.e., both channels from each of the

(continued)

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1. Main Steam Line Isolation (continued)

two associated switch and push buttons are required to actuate the inboard valve trip system and both channels from each of the two associated switch and push buttons are required to actuate the outboard valve trip system).

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-out-of-two logic trip systems. For the Manual Initiation Function of the Group 3 PCIVs, four channels are required to actuate a trip system (a four-out-of-four logic trip system). One trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system logic closes one of the two valves on each penetration so that operation of either trip system isolates the penetration.

The exceptions to this arrangement are the Traversing In-core Probe (TIP) System valves/drives and the Group 5 PCIVs. For the TIP System valves and drive mechanisms, only one trip system (the inboard valve system) is provided. When the trip system actuates, the drive mechanisms withdraw the TIPs, and when the TIPs are fully withdrawn, the ball valves close. The Group 5 PCIVs need only one trip system (the inboard valve system) to isolate all Group 5 valves.

Reactor Vessel Level-Low, Level 3 Function isolates the Group 5 valves. Reactor Vessel Water Level-Low, Low, Level 2 Function isolates the Group 2, 3, and 4 valves. Drywell Pressure-High and Manual Initiation Functions isolates the Group 2, 3, 4, and 5 valves. Reactor Building Vent Exhaust Plenum Radiation-High Function isolates the Group 3 valves.

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(continued)

3. Reactor Core Isolation Cooling System Isolation

Most Functions receive input from two channels, with each channel in one trip system using one-out-of-one logic. One of the two trip systems is connected to the inboard valves and the other trip system is connected to the outboard valve on the RCIC penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement are the RCIC Steam Supply Pressure-Low and the RCIC Turbine Exhaust Diaphragm Pressure-High Functions. These Functions receive input from four steam supply pressure and four turbine exhaust diaphragm pressure channels, respectively. The outputs from these channels are connected into two-out-of-two trip systems, each trip system isolating the inboard or outboard RCIC valves. In addition, the RCIC System Isolation Manual Initiation Function has only one channel, which isolates the outboard RCIC valve only (provided an automatic initiation signal is present).

RCIC Isolation Functions isolate the Group 8 valves.

4. Reactor Water Cleanup System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Functions 4.f and 4.g (Pump Room Area Temperature and Differential Temperature-High) have one channel in each trip system in each room for a total of four channels per Function, and Function 4.i (RWCU Line Routing Area Temperature-High) has one channel in each trip system in each room for a total of eight channels per Function, but the logic is the same (one-out-of-one). Each of the two trip systems is connected to one of the two valves on the RWCU penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement are the Reactor Vessel Water Level-Low Low, Level 2, the SLC System Initiation, and the Manual Initiation Functions. The Reactor Vessel Water Level-Low Low, Level 2 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two-out-of-two trip systems, each trip system isolating one of the two RWCU valves. The SLC System Initiation Function receives input from two channels (one from each SLC pump). The outputs are connected into a one-out-of-two trip system.

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BACKGROUND 4. Reactor Water Cleanup System Isolation (continued)

with the trip system closing only the outboard valve. The Manual Initiation Function uses four channels, two per each switch and push button. Both channels from one switch and push button input into one trip system and both channels from the other switch and push button input into the other trip system, with the channels connected in a two-out-of-two logic. Each trip system isolates one of the two RWCU valves.

RWCU Isolation Functions isolate the Group 7 valves.

5. RHR Shutdown Cooling System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Functions 5.a and 5.b (Pump Room Area Temperature and Pump Room Area Ventilation Differential Temperature-High) have one channel in each trip system in each room for a total of four channels per Function, and Function 5.c (Heat Exchanger Area Temperature-High) has one channel in each trip system in each room for a total of eight channels per Function, but the logic is the same (one-out-of-one). One of the two trip systems is connected to the outboard valves on each shutdown cooling penetration (reactor vessel head spray, shutdown cooling return, and shutdown cooling suction lines) and the other trip system is connected to the inboard valve on the shutdown cooling suction line penetration so that operation of either trip system isolates the penetrations. The exceptions to this arrangement are the Reactor Vessel Water Level-Low, Level 3 and the Manual Initiation Functions. The Reactor Vessel Water Level-Low, Level 3 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, each trip system isolating the inboard or outboard valves. The Manual Initiation Function uses four channels, two per each switch and push button. Both channels from one switch and push button input into one trip system and both channels from the other switch and push button input into the other

(continued)

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5. RHR Shutdown Cooling System Isolation (continued)

trip system, with the channels connected in a two-out-of-two logic. One trip system isolates the inboard valve and the other trip system isolates the outboard valves.

The RHR Shutdown Cooling Isolation Functions isolate the Group 6 valves.

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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.

Primary containment isolation instrumentation satisfies Criterion 3 of Reference 3. 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. Each channel must also respond within its assumed response time, where appropriate.

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,

(continued)

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(continued)

the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

Certain Emergency Core Cooling Systems (ECCS) and RCIC valves (e.g., minimum flow) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS and RCIC. Some instrumentation and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "ECCS Instrumentation," and LCO 3.3.5.2, "RCIC System Instrumentation," and are not included in this LCO.

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.

1. Main Steam Line Isolation

1.a. Reactor Vessel Water Level—Low Low, Level 2

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, Level 2 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with isolation is assumed in the analysis of the

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 1.a. Reactor Vessel Water Level—Low Low, Level 2
(continued)

recirculation line break (Ref. 1). The isolation of the MSL on Level 2 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four differential pressure 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, Level 2 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, Level 2 Allowable Value is chosen to be the same as the ECCS Level 2 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/hour 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. 4). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hour) 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 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

The MSL low pressure signals are initiated from four sensors that are connected to the MSL header. The sensors are arranged such that, even though physically separated from each other, each sensor is able to detect low MSL pressure.

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1.b. Main Steam Line Pressure—Low (continued)

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. 4).

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 stream line break (MSLB) accident (Ref. 5). 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 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 sense d/p across a flow restrictor). The differential pressure switches are arranged such that, even though physically separated from each other, all four connected to one steam line would be able to detect the high flow. Four channels of Main Steam Line Flow—High Function for each MSL (two channels 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.

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1.c. Main Steam Line Flow-High (continued)

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

This Function isolates the Group 1 valves.

1.d. Condenser Vacuum-Low

The Condenser Vacuum-Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum (Ref. 6). Since the integrity of the condenser is an assumption in offsite dose calculations (Ref. 7), the Condenser Vacuum-Low 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 signals are derived from four vacuum switches that sense the vacuum in the condenser. Four channels of Condenser Vacuum-Low Function are available and are required to be OPERABLE to ensure 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 throttle valves (TTVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TTVs are closed.

This Function isolates the Group 1 valves.

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1.e, 1.f. Main Steam Tunnel Temperature and Differential
Temperature-High

Temperature and Differential Temperature-High is provided to detect a leak in a main steam line, 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 FSAR, since bounding analyses are performed for large breaks such as MSLBs.

Temperature-High signals are initiated from thermocouples located in the area being monitored. Four channels of Main Steam Tunnel Temperature-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Each Function has one temperature element.

Eight thermocouples provide input to the Main Steam Tunnel Differential Temperature-High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system. Four channels of Main Steam Tunnel Differential Temperature-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The ambient and differential temperature monitoring Allowable Value is chosen to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 1 valves.

1.g. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the MSL isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function.

(continued)

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1.g. Manual Initiation (continued)

It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. Eight channels of Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the MS� Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 1 valves.

2. Primary Containment Isolation

2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates 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 Level 3 and 2 supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low, Level 2 Functions associated with isolation are implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure 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, Level 3 Function and four channels of Reactor Vessel Water Level—Low Low, Level 2

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY 2.a, 2.b. Reactor Vessel Water Level-Low, Level 3 and Reactor Vessel Water Level-Low Low, Level 2 (continued)

Function are available and are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level-Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level-Low, Level 3 Allowable Value (LCO 3.3.1.1), and the Reactor Vessel Water Level-Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level-Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since isolation of these valves is not critical to orderly plant shutdown.

The Reactor Vessel Water Level-Low, Level 3 Function isolates the Group 5 valves. The Reactor Vessel Water Level-Low Low, Level 2 Function isolates the Group 2, 3, and 4 valves.

The Reactor Vessel Water Level-Low Low, Level 2 Function (MS-LS-61A-D) is also used to initiate the LOCA Time Delay Relays of LCO 3.3.5.1. These LOCA Time Delay Relays stagger ECCS pump loading when the ECCS power source is aligned to the 230 kV offsite circuit to assure ECCS loading, during pump starts, does not overload the offsite source transformer. This branching to LCO 3.3.5.1 requires instrument OPERABILITY when LCO 3.3.5.1 LOCA Time Delay Relay Function is required to be OPERABLE. A Note (e) has been provided to Table 3.3.6.1-1 that identifies Function 2b channels provide one set of initiation signals to the LCO 3.3.5.1 LOCA Time Delay Relay function. Actuation of either required instrument channel per trip system will initiate the LOCA Time Delay Logic for the low pressure ECCS Function (LPCS/LPCI-A or LPCS-B/LPCI-C).

The LCO Actions of 3.3.6.1 (place the channel in trip) may not be the more restrictive Action and Completion Times required of these Level 2 instruments. The LOCA Time Delay Relay channel Actions in LCO 3.3.5.1 are more restrictive if the associated ECCS subsystems are required to be OPERABLE. This is because the LCO 3.3.6.1 Action to place the channel in trip will complete part of the logic for both ECCS subsystems in the division (assuming the instrument failure

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low, Level 2 (continued)

does not already result in the channel being in a tripped condition). If the 230 kV offsite source is supplying the safety buses, the LOCA Time Delay Relays will start timing out immediately and will no longer sequence the delay after HPCS pump starts. If the 230 kV offsite source is not supplying safety buses, the LOCA Time Delay Relays will begin timing out upon transfer to the 230 kV source supply rather than initiating on a LOCA signal at the same time because the HPCS pump starts from different reactor Level 2 instruments. In either case, the LOCA Time Delay Relays may not be properly sequenced to delay start of the low pressure ECCS subsystems tied to when the HPCS pump starts.

2.c. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the drywell. The isolation of some of the PCIVs 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 FSAR 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 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 RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

The above Function isolates the Group 2, 3, 4, and 5 valves.

The Drywell Pressure—High Function is also used to initiate the LOCA Time Delay Relays of LCO 3.3.5.1. These LOCA Time Delay Relays stagger ECCS pump loading when the ECCS power source is aligned to the 230 kV offsite circuit to assure ECCS loading, during pump starts, does not overload the offsite source transformer. This branching to LCO 3.3.5.1

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2.c. Drywell Pressure-High (continued)

requires instrument OPERABILITY when LCO 3.3.5.1 LOCA Time Delay Relay Function is required to be OPERABLE. A Note (e) has been provided to Table 3.3.6.1-1 that identifies Function 2c channels provide one set of initiation signals to the LCO 3.3.5.1 LOCA Time Delay Relay function. Actuation of either required instrument channel per trip system will initiate the LOCA Time Delay Logic for the low pressure ECCS Function (LPCS/LPCI-A or LPCI-B/LPCI-C). Thus, actuation of either Drywell Pressure-High instrument will complete the logic for both subsystems in the division.

The LCO Actions of 3.3.6.1 (place the channel in trip) may not be the more restrictive Action and Completion Times required of these Drywell Pressure-High instruments. The LOCA Time Delay Relay channel Actions in LCO 3.3.5.1 are more restrictive if the associated ECCS subsystems are required to be OPERABLE. This is because the LCO 3.3.6.1 Action to place the channel in trip will complete part of the logic for both ECCS subsystems in the division (assuming the instrument failure does not already result in the channel being in a tripped condition). If the 230 kV offsite source is supplying the safety buses, the LOCA Time Delay Relays will start timing out immediately and will no longer sequence the delay after HPCS pump starts. If the 230 kV offsite source is not supplying safety buses, the LOCA Time Delay Relays will begin timing out upon transfer to the 230 kV source supply rather than initiating on a LOCA signal at the same time as HPCS (pump starts from different Drywell Pressure-High instruments). In either case, the LOCA Time Delay Relays may not be properly sequenced to delay start of the low pressure ECCS subsystems tied to when the HPCS pump starts.

2.d. Reactor Building Vent Exhaust Plenum Radiation-High

High ventilation 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 Radiation-High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 2.d. Reactor Building Vent Exhaust Plenum Radiation-High
(continued)

The Reactor Building Vent Exhaust Plenum Radiation-High signals are initiated from radiation detectors that are located in the ventilation exhaust plenum. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Four channels of Reactor Building Vent Exhaust Plenum Radiation-High 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 ensure offsite doses remain below 10 CFR 50.67 limits.

This Function isolates the Group 3 valves.

2.e. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the primary containment isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

For the Group 3 valves, there are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. For the Group 2, 4, and 5 valves, there are two switch and push buttons (with two channels per switch and push button) for the logic, one switch and push button per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the Primary Containment Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

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2.e. Manual Initiation (continued)

This Function isolates the Group 2, 3, 4, and 5 valves.

3. Reactor Core Isolation Cooling System Isolation

3.a. RCIC Steam Line Flow-High

RCIC Steam Line Flow-High Function is provided to detect a break of the RCIC steam lines and initiates closure of the steam line isolation valves. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and core uncovering can occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any FSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow-High signals are initiated from two differential pressure switches that are connected to the system steam lines. Two channels of RCIC Steam Line Flow-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 be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

This Function isolates the Group 8 valves.

3.b. RCIC Steam Line Flow-Time Delay

The RCIC Steam Line Flow-Time Delay is provided to prevent false isolations on RCIC Steam Line Flow-High during system startup transients and therefore improves system reliability. This Function is not assumed in any FSAR transient or accident analyses since the bounding analysis

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3.b. RCIC Steam Line Flow-Time Delay (continued)

is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow-Time Delay Function delays the RCIC Steam Line Flow-High signals by use of time delay relays. When an RCIC Steam Line Flow-High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels of RCIC Steam Line Flow-Time Delay 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 chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

This Function isolates the Group 8 valves.

3.c. RCIC Steam Supply Pressure-Low

Low RCIC steam supply pressure indicates that the pressure of the steam in the RCIC turbine may be too low to continue operation of the RCIC turbine. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the FSAR. However, it also provides a diverse signal to indicate a possible system break. These instruments are included in the Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 3.

The RCIC Steam Supply Pressure-Low signals are initiated from four pressure switches that are connected to the RCIC steam line. Two channels of RCIC Steam Supply 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 is selected to be high enough to prevent damage to the RCIC turbine.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

3.c. RCIC Steam Supply Pressure - Low (continued)

This Function isolates the Group 8 valves.

3.d. RCIC Turbine Exhaust Diaphragm Pressure - High

High turbine exhaust diaphragm pressure indicates that the pressure may be too high to continue operation of the RCIC turbine. That is, one of two exhaust diaphragms has ruptured and pressure is reaching turbine casing pressure limits. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the FSAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 3.

The RCIC Turbine Exhaust Diaphragm Pressure - High signals are initiated from four pressure switches that are connected to the area between the rupture diaphragms on the RCIC turbine exhaust line. Four channels of RCIC Turbine Exhaust Diaphragm 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 is selected to be low enough to prevent damage to the RCIC turbine.

This Function isolates the Group 8 valves.

3.e, 3.f, 3.g. Area Temperature and Differential Temperature - High

Area Temperature 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 FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 3.e, 3.f, 3.g. Area Temperature and Differential Temperature-High (continued)

Area Temperature-High signals are initiated from thermocouples that are located in the room that is being monitored. Two instruments for each Function monitor each associated area. Four channels of Area Temperature-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the RCIC equipment room area and two channels for the RWCU/RCIC steam line routing area.

There are four thermocouples that provide input to the RCIC Equipment Room Area Differential Temperature-High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of two available channels. Two channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 8 valves.

3.h. Manual Initiation

The Manual Initiation push button channel introduces a signal into the RCIC System isolation logic that is redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There is one push button for RCIC. One channel of Manual Initiation Function is available and is required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RCIC System Isolation automatic Functions are

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

3.h. Manual Initiation (continued)

required to be OPERABLE. As noted (footnote (b) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 8 RCIC isolation valve since the signal only provides input into one of the two trip systems.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button.

This Function isolates the outboard Group 8 valve.

4. Reactor Water Cleanup System Isolation

4.a, 4.c. Differential Flow and Blowdown 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 or blowdown piping 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 or high blowdown flow is sensed to prevent exceeding offsite doses. A time delay (Function 4.b, described below) is provided to prevent spurious trips of the Differential Flow-High Function during most RWCU operational transients. These Functions are not assumed in any FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from one flow element and transmitter that are connected to the inlet (from the reactor vessel) and two flow elements and transmitters from the outlets (to condenser and feedwater) of the RWCU System. The outputs of the transmitters are compared (in a common summer) and the output is sent to two flow switches. If the difference between the inlet and outlet 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 in the logic

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

4.a, 4.c. Differential Flow and Blowdown Flow-High
(continued)

downstream of the common summer can preclude the isolation function. Since some portions of the two channels are common (e.g., flow elements, transmitters, summer), both channels must be considered inoperable if a common component is inoperable.

The high blowdown flow signals are initiated from one flow element and two flow transmitters that are connected to the outlet (to condenser and radwaste) of the RWCU System. The outputs of the transmitters are sent to two flow switches. Two channels of Blowdown Flow-High Function are available and are required to be OPERABLE to ensure that no single instrument failure downstream of the common flow element can preclude the isolation function. Since the flow element is common, both channels must be considered inoperable if the flow element is inoperable.

The Differential Flow-High Allowable Value ensures that the break of the RWCU piping is detected. The Blowdown Flow-High Allowable Value ensures that the break of the RWCU blowdown piping is detected.

This Function isolates the Group 7 valves.

4.b. Differential Flow-Time Delay

The Differential Flow-Time Delay is provided to avoid RWCU System isolations due to operational transients (such as pump starts and mode changes). During these transients the inlet and return flows become unbalanced for short time periods and Differential Flow-High will be sensed without an RWCU System break being present. Credit for this Function is not assumed in the FSAR accident or transient analysis, since bounding analyses are performed for large breaks such as MSLBs.

The RWCU Differential Flow-Time Delay Function delays the RWCU Differential Flow-High signals by use of time delay relays. When an RWCU Differential Flow-High signal is generated, the time delay relays delay the tripping of the associated RWCU isolation trip system for a short time. Two

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY4.b. Differential Flow-Time Delay (continued)

channels for Differential Flow-Time Delay Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow-Time Delay Allowable Value is selected to ensure that the MSLB outside containment remains the limiting break for FSAR analysis for offsite dose calculations.

This function isolates the Group 7 valves.

4.d, 4.e, 4.f, 4.g, 4.h, 4.i. Area Temperature and Differential Temperature-High

Area Temperature and Differential Temperature-High is 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. Credit for these instruments is not taken in any transient or accident analysis in the FSAR, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature-High signals are initiated from thermocouples that are located in the room that is being monitored. There are 16 thermocouples that provide input to the Area Temperature-High Functions (two per area). Sixteen channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the heat exchanger room area, four channels for the pump room areas (two per room), two channels for the RWCU/RCIC line routing area, and eight channels for the RWCU line routing areas (two per room).

There are 12 thermocouples that provide input to the Differential Temperature-High Functions. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

4.d, 4.e, 4.f, 4.g, 4.h, 4.i. Area Temperature and
Differential Temperature-High (continued)

thermocouples that are located in the inlet and outlet of the area cooling system for a total of six available channels (two per area). Six channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the heat exchanger area and four channels for the pump room areas (two per room).

The Area Temperature and Differential Temperature-High Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 7 valves.

4.j. Reactor Vessel Water Level-Low Low, Level 2

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, isolation of some reactor vessel interfaces occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level-Low Low, Level 2 Function associated with RWCU isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Reactor Vessel Water Level-Low Low, Level 2 signals are initiated from differential pressure 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, Level 2 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, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level-Low Low, Level 2 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.j. Reactor Vessel Water Level - Low Low, Level 2
(continued)
This Function isolates the Group 7 valves.

4.k. 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. 8). SLC System initiation signals are initiated from the two SLC pump start signals.

Two channels (one from each pump) of SLC System Initiation Function are available and are required to be OPERABLE in MODES 1 and 2, since these are the only MODES where the reactor can be critical. Both channels are also required to be OPERABLE in MODES 1, 2, and 3, since the SLC System is used to maintain suppression pool pH at or above 7 following a LOCA to ensure iodine will be retained in the suppression pool water. These MODES are consistent with the Applicability for the SLC System (LCO 3.1.7). Compliance with Reference 9 (Columbia Generating Station requires both SLC pumps be started to inject boron) ensures no single instrument failure can preclude the isolation function. As noted (footnote (c) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 7 RWCU isolation valve since the signal only provides input into one of the two trip systems.

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.

This Function isolates the Group 7 valves.

4.l. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RWCU System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

4.1. Manual Initiation (continued)

Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two switch and push buttons (with two channels per switch and push button) for the logic; one switch and push button per trip system. Four channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RWCU System Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 7 valves.

5. RHR Shutdown Cooling System Isolation

5.a, 5.b, 5.c. Area Temperature and Differential Temperature-High

Area Temperature and Differential Temperature-High is provided to detect a leak from the associated system 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 FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature-High signals are initiated from thermocouples that are located in the room that is being monitored. Two instruments for each Function monitor each area. Twelve channels for Area Temperature-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are four channels for the pump room areas (two per room) and eight channels for the heat exchanger areas (two per room).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 5.a, 5.b, 5.c. Area Temperature and Differential Temperature-High (continued)

Eight thermocouples provide input to the Differential Temperature-High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of four available channels (two per pump room). Four channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Area Temperature and Differential Temperature-High Functions are only required to be OPERABLE in MODE 3. In MODES 1, and 2, the Reactor Vessel Pressure-High Function and other administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 6 valves.

5.d. Reactor Vessel Water Level-Low, Level 3

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, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level-Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs. The RHR Shutdown Cooling System isolation on Level 3 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.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

5.d. Reactor Vessel Water Level-Low, Level 3 (continued)

Reactor Vessel Water Level-Low, Level 3 signals are initiated from differential pressure 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, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d) to Table 3.3.6.1-1), only one trip system is required to be OPERABLE in MODES 4 and 5 provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level-Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering reactor vessel level to the top of the fuel. In MODES 1 and 2, the Reactor Vessel Pressure-High Function and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Reactor Vessel Water Level-Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level-Low, Level 3 Allowable Value (LCO 3.3.1.1) since the capability to cool the fuel may be threatened.

This Function isolates the Group 6 valves.

5.e. Reactor Vessel Pressure-High

The Shutdown Cooling System Reactor Vessel Pressure-High Function is provided to isolate the shutdown cooling portion of the RHR System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario and credit for the interlock is not assumed in the accident or transient analysis in the FSAR.

The Reactor Steam Dome-High pressure signals are initiated from two pressure switches. Two channels of Reactor Steam

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

5.e. Reactor Vessel Pressure-High (continued)

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 Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 6 valves.

5.f. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RHR Shutdown Cooling System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two switch and push buttons (with two channels per switch and push button) for the logic, one switch and push button per trip system. Four channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RHR Shutdown Cooling System Isolation automatic Functions are required to be OPERABLE. While certain automatic Functions are required in MODES 4 and 5, the Manual Initiation Function is not required in MODES 4 and 5, since there are other means (i.e., means other than the Manual Initiation switch and push buttons) to manually isolate the RHR Shutdown Cooling System from the control room.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 6 valves.

(continued)

BASES (continued)

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, a Note has been provided that allows separate Condition entry for each inoperable primary 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 or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 10 and 11) 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 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.

(continued)

BASES

ACTIONS
(continued)

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 MSIV portions of 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 and the MSL drain valves portion of the MSL 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. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, 1.d, 1.e, and 1.f, this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For Functions 2.a, 2.b, 2.c, 2.d, 3.c, 3.d, 4.j, and 5.d, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 3.a, 3.b, 3.e, 3.f, 3.g, 4.a, 4.b, 4.c, 4.d, 4.e, 4.h, 4.k, and 5.e, this would require one trip system to have one channel OPERABLE or in trip. For Functions 4.f, 4.g, 4.i, 5.a, 5.b, and 5.c, each Function consists of channels that monitor several different locations. Therefore, this would require one channel per location to be OPERABLE or in trip (the channels are not required to be in the same trip system). The Condition does not include the Manual Initiation Functions (Functions 1.g, 2.e, 3.h, 4.l, and 5.f), since they are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

The channels in the trip system in the more degraded state should be placed in trip. The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in).

(continued)

BASES

ACTIONS

B.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 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 associated MSLS may be isolated (Required Action D.1), and if allowed (i.e., plant safety analysis allows operation with an MSL isolated), plant operation with the MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. This Required Action will generally only be used if a Function 1.c channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow-High Function channel(s) are inoperable. Alternately, 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). 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.

(continued)

BASES

ACTIONS
(continued)

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 6 hours.

The allowed Completion Time of 6 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 operation 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 channel. For some of the Area Temperature and Differential Temperature Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A Area Temperature channel is inoperable, the A pump room area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump. For the RWCU Blowdown Flow-High Function, the affected penetration flow path(s) may be considered isolated by isolating only the RWCU blowdown piping.

Alternatively, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

The Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

(continued)

BASES

ACTIONS
(continued)

G.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 channel.

The 24 hour Completion Time is acceptable due to the fact that these Functions (Manual Initiation) are not assumed in any accident or transient analysis in the FSAR.

Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip, or any Required Action of Condition F or G 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.

I.1 and I.2

If the channel is not restored to OPERABLE status within the allowed Completion Time, the associated SLC subsystem 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 associated SLC subsystem inoperable or isolating the RWCU System.

The Completion Time of 1 hour is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

(continued)

BASES

ACTIONS
(continued)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.

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 also 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 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. 10 and 11) 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.

SR 3.3.6.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.6.1.1 (continued)

between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based 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 3.3.6.1.2 and SR 3.3.6.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 92 day Frequency of SR 3.3.6.1.2 is based on reliability analysis described in References 10 and 11. The 184 day Frequency of SR 3.3.6.1.3 is based on engineering judgment and the reliability of the components.

SR 3.3.6.1.4 and SR 3.3.6.1.5

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.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.6.1.4 and SR 3.3.6.1.5 (continued)

The Frequencies are based on the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.6

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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.6.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists in the 15 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response time without a specific measurement test (Ref. 12). A note to the surveillance states that channel sensors for Functions 1.a, 1.b, and 1.c are excluded and therefore, it is not required to quantitatively measure the sensor response time to satisfy the requirement to verify ISOLATION INSTRUMENTATION RESPONSE TIME. This is acceptable since the sensor response time can be qualitatively verified by other methods (Reference 12). If the response time of the sensor is not quantitatively measured, the acceptance criteria must be reduced by the time assumed for sensor

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.6.1.7 (continued)

response in the design analyses, as verified by statistical analysis or vendor data. The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. However, failure to meet an ISOLATION SYSTEM RESPONSE TIME due to a PCIV closure time not within limits does not require the associated instrumentation to be declared inoperable; only the PCIV is required to be declared inoperable.

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 month test Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. FSAR, Section 6.2.1.1.
2. FSAR, Chapters 15 and 15.F.
3. 10 CFR 50.36(c)(2)(ii).
4. FSAR, Section 15.1.3.
5. FSAR, Section 15.6.4.
6. FSAR, Section 15.2.5.
7. FSAR, Section 11.3.2.
8. FSAR, Section 9.3.5.2.
9. 10 CFR 50.62.
10. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," June 1989.

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BASES

REFERENCES
(continued)

11. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
 12. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.
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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 (SCIVs) and starts the Standby Gas Treatment (SGT) 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), such that offsite radiation exposures are maintained within the requirements of 10 CFR 50.67 that are part of the NRC staff approved licensing basis. Secondary containment isolation and establishment of vacuum with the SGT System within the assumed time limits ensures that 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 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 electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel 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 (a) reactor vessel water level, (b) drywell pressure, and (c) reactor building vent exhaust plenum radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation parameters. In addition, manual initiation of the logic is provided.

Most Secondary Containment Isolation instrumentation Functions receive input from four channels. The output from these channels are arranged into two two-out-of-two logic trip systems. For the Manual Initiation Function, four channels are required to actuate a trip system (a four-out-of-four logic trip system). In addition to the isolation function, the SGT subsystems are initiated. Each trip system will start one fan in each SGT subsystem, but

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BASES

BACKGROUND
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will only align one SGT subsystem filter train. Automatically isolated secondary containment penetrations are isolated by two isolation valves. Each trip system initiates isolation of one of the two valves on each penetration so that operation of either trip system isolates the penetrations.

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The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of Reference 1 to initiate closure of valves and start the SGT System to limit offsite doses.

Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses.

The secondary containment isolation instrumentation satisfies Criterion 3 of Reference 2. 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 upon 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 setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values 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

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BASES

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LCO, and
APPLICABILITY:
(continued)

the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions when SCIVs and the SGT 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, Level 2

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 SGT System are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level - Low Low, Level 2 Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation of systems on Reactor Vessel Water Level - Low Low, Level 2 support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 1).

Reactor Vessel Water Level - Low Low, Level 2 signals are initiated from differential pressure 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, Level 2 Function are

(continued)

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LCO, and
APPLICABILITY

1. Reactor Vessel Water Level - Low Low, Level 2

(continued)

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, Level 2 Allowable Value was chosen to be the same as the High Pressure Core Spray (HPCS)/Reactor Core Isolation Cooling (RCIC) Reactor Vessel Water Level - Low Low, Level 2 Allowable Value (LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System Actuation"), since this could indicate the capability to cool the fuel is being threatened.

The Reactor Vessel Water Level - Low Low, Level 2 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. In addition, the Function is also required to be OPERABLE during operations with a potential for draining the reactor vessel (OPDRVs) because the capability of isolating potential sources of leakage must be provided to ensure that offsite dose limits are not exceeded if core damage occurs.

The Reactor Water Level - Low Low Level Function (MS-LS-61A-D) is also used to initiate the LOCA Time Delay Relays of LCO 3.3.5.1. A Note (c) is provided to Table 3.3.6.2-1 that identifies Function 1 channels provide one set of initiation signals to the LCO 3.3.5.1 LOCA Time Delay Relay function.

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 SGT System are initiated in order to minimize the potential of an offsite dose release. The isolation on high drywell pressure

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BASES

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LCO, and
APPLICABILITY

2. Drywell Pressure-High (continued)

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 isolation is not assumed in any FSAR accident or transient analysis. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis. High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell-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 chosen to be the same as the RPS Drywell Pressure-High Function Allowable Value (LCO 3.3.1.1) since this is indicative of a loss of coolant accident.

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. Reactor Building Vent Exhaust Plenum Radiation-High

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 or the refueling floor due to a fuel handling accident. When Reactor Building Vent Exhaust Plenum Radiation-High is detected, secondary containment

(continued)

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3. Reactor Building Vent Exhaust Plenum Radiation—High
(continued)

isolation and actuation of the SGT System are initiated to limit the release of fission products as assumed in the FSAR safety analysis (Ref. 1).

The Reactor Building Vent Exhaust Plenum Radiation—High signals are initiated from radiation detectors that are located in the ventilation exhaust plenum, which is the collection point of all reactor building and refueling floor air flow prior to its exhaust to atmosphere. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Four channels of Reactor Building Vent Exhaust Plenum Radiation—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 promptly detect gross failure of the fuel cladding.

The Reactor Building Vent Plenum Exhaust Radiation—High Function is 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 these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required. In addition, the Function is required to be OPERABLE during OPDRVs, because the capability of detecting radiation releases due to fuel failures (due to fuel uncover) must be provided to ensure that offsite dose limits are not exceeded.

4. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the secondary containment isolation logic that are redundant to the automatic protective instrumentation channels, and provide manual isolation capability. There is no specific FSAR safety analysis that

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BASES

APPLICABLE
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LCO, and
APPLICABILITY

4. Manual Initiation (continued)

takes credit for this Function. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, two switch and push buttons per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 and during OPDRVs, since these are the MODES and the other specified condition in which the Secondary Containment Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

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 Condition. However, the Required Actions for inoperable secondary containment isolation 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 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 or

(continued)

BASES

ACTIONS

A.1 (continued)

24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 3 and 4) 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 SGT System. A Function is 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. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two logic trip systems (Functions 1, 2, and 3), this would require one trip system to have two channels, each OPERABLE or in trip. The Condition does not include the Manual Initiation Function (Function 4), since it is not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

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BASES

ACTIONS

B.1 (continued)

The channels in the trip system in the more degraded state should be placed in trip. The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in).

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 SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated valves and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operations to continue.

Alternatively, declaring the associated SCIVs or SGT subsystem 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 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.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

The Surveillances are also 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 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 Action(s) taken.

This Note is based on the reliability analysis (Refs. 3 and 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 SCIVs will isolate the associated penetration flow paths and the SGT System will initiate when necessary.

SR 3.3.6.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument 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.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.6.2.1 (continued)

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 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based upon the reliability analysis of References 4 and 5.

SR 3.3.6.2.3

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 Frequency is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing, performed on SCIVs and the SGT 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.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.6.2.4 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 15.6.5.
 2. 10 CFR 50.36(c)(2)(ii).
 3. NEDO-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
 4. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
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B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Filtration (CREF) System Instrumentation

BASES

BACKGROUND

The CREF 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 CREF subsystems are each capable of fulfilling the stated safety function. The instrumentation and controls for the CREF System automatically initiate action to pressurize the main control room (MCR) to minimize the consequences of radioactive material in the control room environment.

In the event of a loss of coolant accident (LOCA) signal (Reactor Vessel Water Level—Low Low, Level 2, Drywell Pressure—High, or Reactor Building Vent Exhaust Plenum Radiation—High), the CREF System is automatically started in the pressurization mode. Sufficient outside air is drawn in through two separate remote fresh air intakes to keep the MCR slightly pressurized with respect to the radwaste and turbine buildings. The outside air is then circulated through the charcoal filter. Both intakes are physically remote from all plant structures.

The CREF System automatic initiation instrumentation has two trip systems: one trip system initiates one CREF subsystem, while the second trip system initiates the other CREF subsystem (Ref. 1). Each trip system receives input from the automatic initiation Functions listed above. Each of these Functions are arranged in a two-out-of-two logic for each trip system. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a CREF System initiation signal to the initiation logic.

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BASES (continued)

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The ability of the CREF System to maintain the habitability of the MCR is explicitly assumed for certain accidents as discussed in the FSAR safety analyses (Refs. 2 and 3). CREF 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 set by GDC 19 of 10 CFR 50, Appendix A and 10 CFR 50.67.

CREF instrumentation satisfies Criterion 3 of Reference 4.

The OPERABILITY of the CREF System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. 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.

Allowable Values are specified for each CREF System Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. These nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint that is 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., trip relay) changes state. The analytic limits are derived from the limiting values of the process

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parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

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, Level 2

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. A low reactor vessel water level could indicate a LOCA, and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from four differential pressure 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, Level 2 Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation. The Allowable Value for the Reactor Vessel Water Level—Low Low, Level 2 is chosen to be the same as the Secondary Containment Isolation Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.6.2).

The Reactor Vessel Water Level—Low Low, Level 2 Function is required to be OPERABLE in MODES 1, 2, and 3, and during operations with a potential for draining the reactor vessel (OPDRVs), to ensure that the control room personnel are protected. In MODES 4 and 5, at times other than during OPDRVs, the probability of a vessel draindown event releasing radioactive material into the environment, or of a LOCA, is minimal. Therefore this Function is not required.

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BASES

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2. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). A high drywell pressure signal could indicate a LOCA and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Drywell Pressure—High signals are initiated from four pressure switches that sense drywell pressure. Four channels of Drywell Pressure—High Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation.

The Drywell Pressure—High Allowable Value was chosen to be the same as the Secondary Containment Isolation Drywell Pressure—High Allowable Value (LCO 3.3.6.2).

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. In MODES 4 and 5, the Drywell Pressure—High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure—High setpoint.

3. Reactor Building Vent Exhaust Plenum Radiation—High

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 or the refueling floor due to a fuel handling accident. When Reactor Building Vent Exhaust Plenum Radiation—High is detected, the CREF System is automatically initiated since this radiation release could result in radiation exposure to control room personnel.

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BASES

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3. Reactor Building Vent Exhaust Plenum Radiation—High
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Reactor Building Vent Exhaust Plenum Radiation—High signals are initiated from four radiation monitors that measure radiation in the reactor building vent. Four channels of Reactor Building Vent Exhaust Plenum Radiation—High Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation.

The Reactor Building Vent Exhaust Plenum Radiation—High Allowable Value was chosen to be the same as the Secondary Containment Isolation Reactor Building Vent Exhaust Plenum Radiation—High Allowable Value (LCO 3.3.6.2).

The Reactor Building Vent Exhaust Plenum Radiation—High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. The Function is also required to be OPERABLE during OPDRVs, in case of fuel uncover that could cause a radioactive release to the environment.

ACTIONS

A Note has been provided to modify the ACTIONS related to CREF 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 CREF 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 CREF System instrumentation channel.

(continued)

BASES

ACTIONS
 (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.7.1-1. The applicable Condition specified in the Table is Function dependent. Each time an inoperable channel is discovered, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 24 hours has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate. If the Function is not maintaining CREF System initiation capability, the CREF System must be declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action B.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable, untripped channels in the same Function in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

(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 D must be entered and its Required Actions taken.

C.1 and C.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 12 hours has been shown to be acceptable (Refs. 5 and 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 12 hour allowance of Required Action C.2 is not appropriate. If the Function is not maintaining CREF System initiation capability, the CREF System must be declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action C.1). This Completion time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

untripped Drywell Pressure-High channels in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

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 C.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 D must be entered and its Required Actions taken.

D.1 and D.2

With any Required Action and associated Completion Time of Condition B, C, or D not met, the associated CREF subsystem must be placed in the pressurization mode of operation (Required Action D.1) to ensure that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the CREF subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the CREF subsystem(s). Alternately, if it is not desired to start the subsystem, the CREF subsystem associated with inoperable, untripped channels must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREF subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels, or for placing the associated CREF subsystem in operation.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each CREF System instrumentation Function are located in the SRs column of Table 3.3.7.1-1.

The Surveillances are also 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 CREF System 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 (Refs. 5, 6, and 7) 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 CREF System will initiate when necessary.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.7.1.1 (continued)

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 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 channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 5, 6, and 7.

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 Frequency is based on the assumption of an 18 month calibration interval in the determination of the magnitude of 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 3.7.3, "Control Room Emergency Filtration (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 7.3.1.1.7.
 2. FSAR, Section 6.4.
 3. FSAR, Chapter 15.
 4. 10 CFR 50.36(c)(2)(ii).
 5. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.
 6. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
 7. NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
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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 buses. 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.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for the Division 1, 2, and 3 buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage.

The Division 1 and 2 TR-S Loss of Voltage and the Division 3 Loss of Voltage Functions are monitored by two instruments per bus whose output trip contacts are arranged in a one-out-of-two logic configuration per bus. The Division 1 and 2 TR-B Loss of Voltage Function is monitored by one instrument per bus where output trip contacts are arranged in a one-out-of-one logic configuration per bus. The Degraded Voltage Function for Division 1 and 2 4.16 kV Engineered Safety Feature (ESF) buses is monitored by three instruments per bus whose output trip contacts are arranged in a two-out-of-three logic configuration per bus. The Degraded Voltage Function for the Division 3 4.16 kV ESF bus is monitored by two instruments whose output trip contacts are arranged in a two-out-of-two logic configuration (Ref. 1).

Upon a TR-S loss of voltage signal on the Division 1 and 2 4.16 kV ESF buses, the associated DG is started and a three and one half second timer is initiated to allow recovery time for the TR-S source of power. If the loss of voltage was caused by an electrical fault, this timer is long enough to coordinate with the overcurrent protection relays. At the end of the three and one half second timer, if bus

(continued)

BASES

BACKGROUND
(continued)

voltage is still below the setpoint (as sensed by one of the two channels), the Division 1 and 2 1E bus breakers for TR-N1 and TR-S are tripped, the bus ESF loads are shed (except for the 480 V buses) and an additional timer is initiated (a two second timer). After the two second time delay an attempt is made to close the TR-B breaker if the backup source is available. These two timers constitute the Division 1 and 2 TR-S Loss of Voltage-Time Delay Function. In addition, at the end of the three and one half second timer, a third timer is initiated that inhibits the DG breakers close signal for four seconds. This provides enough time for the 4.16 kV ESF buses to connect to the backup source if it is available. After the four second delay the DG breaker is allowed to close (if the TR-B breaker did not close) once the DG attains the proper frequency and voltage. This timer is not considered part of the LOP Instrumentation (it is tested in LCO 3.8.1, "AC Sources-Operating," and LCO 3.8.2, "AC Sources-Shutdown").

Upon a TR-B loss of voltage signal on the Division 1 and 2 4.16 kV ESF buses while these buses are tied to TR-B, a 3.5 second timer is initiated to allow time to verify loss of voltage and to establish the TR-B source of power. At the end of the 3.5 second timer, if bus voltage is still below the setpoint, the Division 1 and 2 1E bus breakers for TR-B are tripped. This timer constitutes the Division 1 and 2 TR-B Loss of Voltage-Time Delay Function. The associated DG is started and the bus ESF loads are shed (except the 480 V buses) by the TR-S Loss of Voltage Function, as described earlier.

Upon a loss of voltage signal on the Division 3 4.16 kV ESF bus, a two second timer starts to allow recovery time for the failing source. If the loss of voltage was caused by an electrical fault, this timer is long enough to coordinate with the overcurrent protection relays. At the end of the two second time delay the preferred source breaker is tripped if bus voltage is still below the setpoint (as sensed by one of the two channels). In addition, at the end of the two second time delay, a 1.3 second timer is initiated. At the end of the 1.3 second timer the HPCS DG is started and the DG breaker closes as the DG reaches rated frequency. These two timers constitute the Division 3 Loss of Voltage-Time Delay Function.

(continued)

BASES

BACKGROUND
(continued)

Upon degraded voltage on Division 1, 2, or 3 4.16 kV ESF buses there is an eight second time delay before any action is taken to allow the degraded condition to recover. The Division 1 and 2 eight second time delay is further divided into a primary time delay of five seconds and a secondary time delay of 3 seconds. There are two primary time delay relays, but only one secondary time delay relay. The secondary time delay relay is started when both degraded voltage relays are tripped and their respective primary time delays have timed out. After the eight second time delay the feeder breakers connecting the sources to the respective 4.16 kV ESF buses are tripped. The actions for Division 1 and 2 at this point during the degraded voltage condition are the same (utilizes the same timers) as the loss of voltage condition for Division 1 and 2 except the first three and one half second timer is bypassed. The actions for Division 3 at this point during the degraded voltage condition are the same (utilizes the same timers) as the loss of voltage condition for Division 3 except the first two second timer is bypassed.

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

The LOP instrumentation is required for the Engineered Safety Features 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 analyzed accidents in References 2, 3, and 4 in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of two of the three DGs (i.e., the DG function) based on the loss of offsite power during a loss of coolant accident (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 Reference 5.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

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.

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 setpoint does 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 changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account. Some functions have both an upper and lower analytic limit that must be evaluated. The Allowable Values and the trip setpoints are derived from both an upper and lower analytic limit using the methodology described above. Due to the upper and lower analytic limits, Allowable Values of these Functions appear to incorporate a range. However, the upper and lower Allowable Values are unique, with each Allowable Value associated with one unique analytic limit and trip setpoint.

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)

1.a, 1.b, 1.c, 1.d, 2.a, 2.b. 4.16 kV Emergency Bus
Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be 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 when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short 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 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, shed certain loads, and coordinate with overcurrent protection relays, but short enough to ensure that power is available to the required equipment.

Two channels of Division 1 and 2 TR-S and Division 3 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated emergency bus are available and are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Division 1 and 2 TR-B 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated emergency bus is available and is required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1, and LCO 3.8.2, for Applicability Bases for the DGs.

1.e, 1.f, 1.g, 2.c, 2.d. 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, power may be insufficient for starting large 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 1.e, 1.f, 1.g, 2.c, 2.d. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)
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.

Three channels of the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)-4.16 kV Basis and -Primary Time Delay Functions per associated emergency bus are available, but only two channels of Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)-4.16 kV Basis and -Primary Time Delay Functions per associated emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)-Secondary Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. Two channels of Division 3 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function and Time Delay Function are available and required to be OPERABLE when the associated DG is required to be OPERABLE. Note (a) has been added for the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) protection requirements to ensure the required Degraded Voltage-4.16 kV Basis and -Primary Time Delay Functions are associated with one another, since only two of the available channels for each Function are required to be OPERABLE. 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

(continued)

BASES

ACTIONS
(continued)

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

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.8.1-1. The applicable Condition specified 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 channels within the same Function result in loss of voltage initiation capability being lost for a DG. Initiation capability is lost if a) both Function 1.a channels for a division are inoperable, b) both Function 1.b channels for a division are inoperable, c) both Function 2.a channels are inoperable, or d) both Function 2.b channels are inoperable. In this situation (loss of initiation capability for a division), the 24 hour allowance of Required Action B.2 is not appropriate and the DG associated with the inoperable channels must be declared inoperable within 1 hour. This ensures that the proper loss of initiation capability check is performed.

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 allowed outage time "clock." The Completion Time only begins upon discovery that a DG cannot be automatically initiated due to inoperable channels

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

within the 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 redundancy of sensors available to provide initiation signals and the redundancy of the onsite AC power source design, an allowable out of service time of 24 hours is provided 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 D must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would cause the initiation.

C.1

With one or more channels of a Function 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 C.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 channel in trip would result in a bus transfer and DG initiation), Condition D 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.

(continued)

BASES

ACTIONS
(continued)

D.1, D.2.1, and D.2.2

If any Required Action and associated Completion Time of Condition B or C is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately (Required Action D.1). 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). Alternately, for Functions 1.c and 1.d only, the TR-B loss of voltage instrumentation, the offsite circuit supply breaker to the associated 4.16 kV ESF bus must be opened immediately (Required Action D.2.1) and the associated offsite circuit declared inoperable immediately (Required Action D.2.2). These alternate Required Actions also provide appropriate compensatory measures since the TR-B loss of voltage instrumentation only affects the loss of voltage trip capability of the alternate offsite circuit.

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 initiation capability. Initiation capability is maintained provided the following can be initiated by the Function (i.e., Loss of Voltage and Degraded Voltage) for two of the three DGs and 4.16 kV ESF buses: DG start, disconnect from the offsite power source, transfer to the alternate offsite power source, if available, DG output breaker closure, and load shed. 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.8.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustments shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY and drift that demonstrates that failure of more than one channel of a given Function in any 31 day interval is rare.

SR 3.3.8.1.2 and SR 3.3.8.1.3

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 Frequencies are based on the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

(continued)

BASES (continued)

- REFERENCES
1. FSAR, Section 8.3.1.1.1.
 2. FSAR, Section 5.2.
 3. FSAR, Section 6.3.
 4. FSAR, Chapter 15.
 5. 10 CFR 50.36(c)(2)(ii).
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B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

The 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 for the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and various valve isolation logic.

The RPS Electric Power Monitoring assembly 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 electric power monitoring assemblies), 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, as well as the main steam isolation valve 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 each RPS bus and its alternate power supply. Each of these circuit breakers has an associated independent set of

(continued)

BASES

BACKGROUND
(continued)

Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the MG set or the alternate power supply exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE
SAFETY ANALYSES

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 disconnecting 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 Reference 2.

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent upon the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply that supports equipment required to be OPERABLE (i.e., if the inservice power supply is not supporting any equipment required to be OPERABLE by Technical Specifications, then the associated electric power monitoring assemblies are not required to be OPERABLE). This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS bus powered components. Each of the inservice electric power monitoring assembly trip logic setpoints is required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly 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

(continued)

BASES

LCO
(continued)

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., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters, including associated line losses, obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process, and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, $120\text{ V} \pm 10\%$ (to all equipment), and $115\text{ V} \pm 10\text{ V}$ (to scram and MSIV solenoids). The most limiting voltage requirement determines the settings of the electric power monitoring instrument channels. 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 electric power monitoring assemblies 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 electric power monitoring assemblies 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, 2, and 3, MODES 4 and 5 with both residual heat

(continued)

BASES

APPLICABILITY
(continued)

removal (RHR) shutdown cooling suction isolation valves open, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System are reduced and only a limited time (72 hours) is allowed to restore the inoperable assembly(s) to OPERABLE status. If the inoperable assembly(s) cannot be restored to OPERABLE status, the associated power supply must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly 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.

Alternatively, 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.

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable, or both power monitoring assemblies 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

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supplies must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE assemblies 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 or removal from service of the electric power monitoring assemblies.

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.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(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 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.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5 with both RHR shutdown cooling suction isolation valves open, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2). Required Action D.1 is provided because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

E.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 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 E.1). This Required Action 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

The Surveillances are modified by a Note to indicate that when an RPS electric power monitoring assembly 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 RPS electric power monitoring assembly for the associated power supply maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the assembly must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This 6 hour allowance is acceptable since it does not significantly reduce the probability that the RPS electric power monitoring assembly function will initiate when necessary.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

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. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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 operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). In addition, if the plant will be shutdown in MODE 4 or 5 for an extended period of time it is acceptable to postpone the Surveillance until the plant is ready to go back to MODE 2 or 3. Performance of the SR immediately after shutdown would jeopardize the reliability of shutdown cooling during a time of high decay heat load. However, prior to restart it is reasonable to perform the surveillance to provide further assurance of the operability of equipment before returning to MODE 1. The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance if it has not been performed in the last 184 days. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.2.2

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 Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly 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 electric power monitoring assembly would be inoperable.

The 24 month Frequency is based on instrument drift analysis, the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. FSAR, Section 8.3.1.1.6.
 2. 10 CFR 50.36(c)(2)(ii).
 3. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Recirculation (RRC) System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes heat at a faster rate 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 RRC 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 RRC 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 two channel adjustable speed drive (ASD) unit 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 driven 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 driven flow are mixed in the jet pump throat section and result in partial pressure recovery. 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.

(continued)

BASES

BACKGROUND
(continued)

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat 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., 65 to 100% 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 ASD provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled.

APPLICABLE
SAFETY ANALYSES

The operation of the RRC 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. 2). 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 the loop with

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

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 (Ref. 2). The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 3), which are analyzed in Chapter 15 of the FSAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. 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. 4).

The transient analyses in Chapter 15 of the FSAR have also been performed for single recirculation loop operation (Ref. 4) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. The APLHGR and MCPR setpoints for single loop operation are specified in the COLR. The APRM flow biased simulated thermal power setpoint is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Recirculation loops operating satisfies Criterion 2 of Reference 5.

LCO

Two recirculation loops are normally required to be in operation with their flows 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.

(continued)

BASES

LCO
(continued) 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)"), and MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") must be applied to allow continued operation.

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 and B.1

With both recirculation loops operating but the flows not matched, the recirculation loops must be restored to operation within 2 hours. If matched flows are not restored, the recirculation loop with lower flow must be declared "not in operation," as required by Required Action A.1. This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing pump speeds to re-establish forward flow or by tripping the pump.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With the requirements of the LCO not met for reasons other than Condition A (e.g., one loop is "not in operation"), the recirculation loops must be restored to operation with matched flows within 4 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits for greater than 2 hours (i.e., Required Action A.1 has been taken). Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to operating limits, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 and 4 hour Completion Times are based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

C.1

With the Required Action and associated Completion Time of Condition B not met, the unit is required to 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.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., < 70% of rated core flow, 75.95×10^6 lbm/hr), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow.

The mismatch is measured in terms of percent of rated recirculation loop drive flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the 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.

REFERENCES

1. FSAR, Sections 6.3 and 15.6.
 2. FSAR, Section 6.3.3.7.2.
 3. FSAR, Section 5.4.1.
 4. FSAR, Section 6.A.
 5. 10 CFR 50.36(c)(2)(ii).
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Recirculation (RRC) 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 RRC 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 10 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 Reference 2.

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 RRC 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 RRC System (LCO 3.4.1).

In MODES 3, 4, and 5, the RRC 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 to reflood 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 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 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 3). 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 any two of the three 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. 3 and 4). 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 (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 may indicate a flow restriction, loss in pump hydraulic performance, leak, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the loop flow versus pump speed relationship must be verified.

Total core flow can be determined from measurements of the recirculation loop drive flows. Once this relationship has been established, increased or reduced total core flow for the same recirculation loop drive flow may be an indication of failures in one or several jet pumps.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.2.1 (continued)

Individual jet pumps in a recirculation loop typically 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.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 3). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 3.

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. 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 until 24 hours after THERMAL POWER exceeds 25% 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. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

REFERENCES

1. FSAR, Sections 6.3 and 15.F.6.
2. 10 CFR 50.36(c)(2)(ii).

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BASES

REFERENCES
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3. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.
 4. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (SRVs) - \geq 25% RTP

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) 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 safety/relief valves (SRVs) 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 are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The SRVs can actuate by either of two modes: the safety mode or the relief mode. (However, for the purposes of this LCO, only the safety mode is required). In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston/cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Seven of the SRVs that provide the safety and relief function are part of the Automatic Depressurization System specified in LCO 3.5.1. "ECCS - Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure 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

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

associated with MSIV position) (Ref. 2). For the purpose of the overpressure protection analysis, 12 of the SRVs with the highest setpoints are assumed to operate in the safety mode. The analysis results demonstrate that the design SRV capacity is capable of maintaining reactor pressure below the ASME Code limit (Ref. 1) 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 most severe pressure transient.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. References 3, 4, and 5 discuss additional events that are expected to actuate the SRVs. The analysis described in Reference 5 also assumes that, for certain events (e.g., ECCS performance during a small break LOCA), of the 12 required OPERABLE SRVs, two SRVs with lift setpoints in the lowest two lift setpoint groups are OPERABLE.

SRVs - \geq 25% RTP satisfy Criterion 3 of Reference 6.

LCO

The safety function of 12 SRVs is required to be OPERABLE, with two SRVs in the lowest two lift setpoint groups OPERABLE. The requirements of this LCO are applicable only to the capability of the SRVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode). In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE SRVs. The results show that with a minimum of 12 SRVs in the safety mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded. While the analysis assumes the overpressurization event is mitigated by SRVs with the highest setpoints (Ref. 2), the small break LOCA analysis (Ref. 5) assumes two of the 12 required OPERABLE SRVs have lift setpoints in the lowest two lift setpoint groups.

The SRV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in

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BASES

LCO
(continued)

References 3, 4, and 5 involving the safety mode are based on these setpoints, but also include the additional uncertainties of $\pm 3\%$ of the nominal setpoint to account for potential setpoint drift 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 or unacceptable core thermal margins.

APPLICABILITY

With THERMAL POWER \geq 25% RTP, the specified number of SRVs must be OPERABLE since there is considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The SRVs may be required to provide pressure relief to limit peak reactor pressure.

The requirements for SRVs in MODE 1 with THERMAL POWER $<$ 25% RTP and in MODES 2 and 3 are discussed in LCO 3.4.4, "SRVs - $<$ 25% RTP." 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 function is not needed during these conditions.

ACTIONS

A.1

With less than the minimum number of required SRVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure, or core thermal margins may be challenged. If one or more required SRVs are inoperable, 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 $<$ 25% RTP within 4 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 3.4.3.1

This Surveillance demonstrates that the required SRVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the SRV safety function lift settings is 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.

SR 3.4.3.2

A manual actuation of each required SRV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine governor valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. If the 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.

The 24 month Frequency was developed based on the SRV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Section 15.2.4.
3. FSAR, Chapter 15.
4. GE-NE-187-24-0992, "WPPSS Nuclear Project 2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.
5. NEDC-32115P, Columbia Generating Station, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.

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BASES

REFERENCES
(continued)

6. 10 CFR 50.36(c)(2)(ii).
 7. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (SRVs) - < 25% RTP

BASES

BACKGROUND A description of the safety/relief valves (SRVs) is provided in the Bases for LCO 3.4.3, "Safety/Relief Valves (SRVs) - \geq 25% RTP."

APPLICABLE SAFETY ANALYSES The overpressure protection system must accommodate the most severe pressure 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). OPERABILITY of SRVs is normally demonstrated during low power operation since an SRV test facility is not available at Columbia Generating Station. Therefore, in order to facilitate testing during power operations, an overpressure transient analysis was performed for the bounding accident at 25% RTP. The analysis assumptions were similar to that in Reference 1; closure of all MSIVs followed by a reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position). For the purpose of the analysis, four of the SRVs with the highest setpoints are assumed to operate in the safety mode (Ref. 2). The analysis results demonstrate that the design SRV capacity is capable of maintaining reactor pressure below the ASME Code limit (Ref. 3) 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 most severe pressure transient.

From an overpressure standpoint, these design basis events are bounded by the MSIV closure with flux scram event described above. References 4 and 5 discuss additional events that are expected to actuate the SRVs.

SRVs - < 25% RTP satisfy Criterion 3 of Reference 6.

LCO The safety function of four SRVs is required to be OPERABLE. The requirements of this LCO are applicable only to the capability of the SRVs to mechanically open to relieve

(continued)

BASES

LCO
(continued)

excess pressure when the lift setpoint is exceeded (safety mode). In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE SRVs. The results show that with a minimum of four SRVs in the safety mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded. Since the analysis assumes the overpressurization event is mitigated by SRVs with the highest setpoints, any four of the 18 SRVs can be used to meet this LCO.

The SRV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in References 4 and 5 involving the safety mode are based on these setpoints, but also include the additional uncertainties of $\pm 3\%$ of the nominal setpoint to account for potential setpoint drift 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.

APPLICABILITY

In MODE 1 with THERMAL POWER < 25% RTP and MODES 2 and 3, the specified number of SRVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The SRVs may be required to limit peak reactor pressure.

The requirements for SRVs with THERMAL POWER \geq 25% RTP are discussed in LCO 3.4.3. 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 cannot 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 function is not needed during these conditions.

(continued)

BASES (continued)

ACTIONS A.1 and A.2

With less than the minimum number of required SRVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If one or more required SRVs 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 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 3.4.4.1

This Surveillance demonstrates that the required SRVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the SRV safety function lift settings is 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.

SR 3.4.4.2

A manual actuation of each required SRV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine governor valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure and flow when the SRVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is 900 psig (consistent with the recommendations of the vendor). Adequate steam flow is represented by THERMAL POWER \geq 10% RTP. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.4.2 (continued)

requirements, prior to reactor startup. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the 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.

The 24 month Frequency was developed based on the SRV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 15.2.4.
 2. Columbia Generating Station Calculation NE-02-94-66, Revision 0, November 13, 1995.
 3. ASME, Boiler and Pressure Vessel Code, Section III.
 4. FSAR, Chapter 15.
 5. GE-NE-187-24-0992, "WPPSS Nuclear Project 2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.
 6. 10 CFR 50.36(c)(2)(ii).
 7. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 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 GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell 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 detrimental to the safety of the facility or the public.

A limited amount of leakage inside the drywell is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of 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, 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. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

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 floor sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of Reference 7.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

BASES

LCO
(continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell atmosphere monitoring and drywell floor drain sump flow monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. 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.

d. 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. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be 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 RCS 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 of piping is very susceptible to IGSCC.

The 4 hour Completion Time is needed to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, 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,

(continued)

BASES

ACTIONS C.1 and C.2 (continued)

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 3.4.5.1

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 3.4.7, "RCS Leakage Detection Instrumentation." Sump flow rate is typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference 8. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. 9).

REFERENCES

1. 10 CFR 50.2.
 2. 10 CFR 50.55a(c).
 3. 10 CFR 50, Appendix A, GDC 55.
 4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows," April 1968.
 5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
 6. FSAR, Section 5.2.5.5.2.
 7. 10 CFR 50.36(c)(2)(ii).
 8. Regulatory Guide 1.45, May 1973.
 9. Generic Letter 88-01, Supplement 1, February 1992.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

RCS PIVs are defined as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB). The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE."

Although this Specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following connected systems:

- a. Residual Heat Removal (RHR) System;
- b. Low Pressure Core Spray System;

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BASES

BACKGROUND
(continued)

- c. High Pressure Core Spray System; and
- d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 6.

APPLICABLE
SAFETY ANALYSES

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment. RCS PIV leakage satisfies Criterion 2 of Reference 7.

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 4).

Reference 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR flowpath are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR shutdown cooling mode of operation.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. 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 the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate, affected RCS PIV flow paths. As such, a Note has been provided that allows separate Condition entry for each affected RCS PIV flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system OPERABILITY, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

A.1

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed manual, de-activated, automatic, or check valve within

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BASES

ACTIONS

A.1 (continued)

4 hours. Required Action A.1 is modified by a Note stating that a check valve used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB.

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseal the leaking PIVs are taken. The 4 hours allows time for these actions, restricts the time of operation with leaking valves, and considers the low probability of a second valve failing during this time period and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. 8).

B.1 and B.2

If leakage cannot be reduced or the system isolated, 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. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times 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.

SURVEILLANCE
REQUIREMENTS

SR 3.4.6.1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. As stated in the LCO section of the Bases, the test pressure may be at a lower pressure than the maximum pressure differential (at the RCS maximum pressure of 1035 psig), provided the observed leakage rate is adjusted in accordance with Reference 4. The actual test pressure shall be \geq 935 psig. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.6.1 (continued)

failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is only required to be performed in MODES 1 and 2. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. 10 CFR 50.2.
 2. 10 CFR 50.55a(c).
 3. 10 CFR 50, Appendix A, GDC 55.
 4. ASME, Boiler and Pressure Vessel Code, Section XI.
 5. NUREG-0677, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," May 1980.
 6. Licensee Controlled Specifications Manual.
 7. 10 CFR 50.36(c)(2)(ii).
 8. NEDC-31339, "BWR Owners' Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," November 1986.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

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 (Ref. 2). 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 rates. The Bases for LCO 3.4.5, "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 at least one of two independently monitored variables, such as sump drain flow changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump flow monitoring system.

The drywell floor drain sump flow monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Reactor Building Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump gravity drains to a reactor building floor drain sump. The drywell floor drain sump piping to the reactor building floor drain sump has a transmitter that supplies flow indication in the main control room. If the

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BASES

BACKGROUND
(continued)

sump drain flow increases to the high flow alarm setpoint, an alarm sounds in the main control room, indicating a LEAKAGE rate from the sump in excess of a preset limit.

The drywell atmosphere monitoring systems (particulate and gaseous) continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring systems are not capable of quantifying leakage rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour (Ref. 3). Larger changes in LEAKAGE rates are detected in proportionally shorter times.

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. 4 and 5). 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. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of Reference 7.

LCO

The drywell floor drain sump flow monitoring system is required to quantify the unidentified LEAKAGE from the RCS. The other monitoring systems (particulate or gaseous) provide early alarms 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. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1

With the drywell floor drain sump flow monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell atmospheric activity monitor will provide indications of changes in leakage.

With the drywell floor drain sump flow monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.5.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

B.1 and B.2

With both gaseous and particulate drywell atmospheric monitoring channels inoperable (i.e., the required drywell atmospheric monitoring system), grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the required monitors.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for restoration recognizes that at least one other form of leakage detection is available.

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BASES

ACTIONS
(continued)

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B 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 in an orderly manner and without challenging plant systems.

D.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

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 required instrumentation (either the drywell floor drain sump flow monitoring system or the drywell atmospheric monitoring channel, as applicable) 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. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring drywell leakage.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.7.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.7.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 5.2.5.5.3.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.

(continued)

BASES

REFERENCES
(continued)

6. FSAR, Section 5.2.5.5.
 7. 10 CFR 50.36(c)(2)(ii).
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the 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, 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 10% 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 FSAR (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. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed the dose guidelines of 10 CFR 50.67. The MSLB analysis (Ref. 2) evaluates two source term cases. The source term

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued) for the first case is based on the Dose Equivalent I-131 limit of 0.2 $\mu\text{Ci/gm}$ provided in the LCO. The second case postulates a pre-accident iodine spike and uses a 4.0 $\mu\text{Ci/gm}$ Dose Equivalent I-131 source term. For the first case, the regulatory limit for the offsite dose is 10% of the limit specified in 10 CFR 50.67. The full offsite dose limit of 10 CFR 50.67 is applicable to the pre-accident iodine spiking case.

The limit on specific activity is a value from a parametric evaluation of typical site locations. This limit is conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of Reference 3.

LCO The specific iodine activity is limited to $\leq 0.2 \mu\text{Ci/gm}$ 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.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 $\mu\text{Ci/gm}$, 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.

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 ≤ 0.2 $\mu\text{Ci/gm}$ within 48 hours, or if at any time it is > 4.0 $\mu\text{Ci/gm}$, it must be determined at least every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than the requirements of 10 CFR 50.67 during a postulated MSLB accident.

Alternately, the plant can be brought to MODE 3 within 12 hours and to 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.

(continued)

BASES

ACTIONS

B.1, B.2.1, B.2.2.1, and B.2.2.2 (continued)

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 bringing the plant to MODES 3 and 4 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 3.4.8.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day 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, "Accident Source Term."
 2. FSAR, Section 15.6.4.
 3. 10 CFR 50.36(c)(2)(ii).
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 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 $\leq 200^{\circ}\text{F}$ in preparation for performing Refueling or Cold Shutdown maintenance operations, or the decay heat must be removed for maintaining the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, 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 Standby Service Water System (LCO 3.7.1, "Standby Service Water (SW) System and Ultimate Heat Sink (UHS)").

APPLICABLE
SAFETY ANALYSES

Decay heat removal by 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 safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System meets Criterion 4 of Reference 1.

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. 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

(continued)

BASES

LCO
(continued)

one subsystem can maintain or 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.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for 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 48 psig (with an associated saturation temperature of 295°F), the RHR Shutdown Cooling 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 48 psig, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above 295°F because this temperature may exceed the analyzed value of the shutdown cooling mode of the RHR System. Decay heat removal at reactor pressures greater than or equal to 48 psig is typically accomplished by condensing the steam in the main condenser. 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.

(continued)

BASES

APPLICABILITY (continued) The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "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.

A.1, A.2, and A.3

With one 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.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

With both 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 calculation or demonstration) 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 and Main Steam Systems, the Reactor Water Cleanup System (by itself, or using feed and bleed in combination with the Control Rod Drive System or Condensate System) and, a combination of an ECCS pump and a safety/relief valve.

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.

B.1, B.2, and B.3

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one 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

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

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.

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 3.4.9.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours 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 achieving less than 48 psig reactor steam dome 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 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.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 at $\leq 200^{\circ}\text{F}$ in preparation for performing Refueling maintenance operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, 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 Standby Service Water (SW) System.

APPLICABLE
SAFETY ANALYSES

Decay heat removal by 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 safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System meets Criterion 4 of Reference 1.

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 SW pump providing cooling to the heat exchanger, and the associated piping and valves. 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

(continued)

BASES

LCO
(continued)

can maintain and reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for 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 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 200°F. Otherwise, a recirculation pump is required to be in operation.

The requirements for decay heat removal in MODE 3 below 48 psig reactor steam dome pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

(continued)

BASES (continued)

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.

A.1

With one of the two 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 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 calculation or demonstration) 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 Reactor Water Cleanup System (by itself, or using feed

(continued)

BASES

ACTIONS

A.1 (continued)

and bleed in combination with the Control Rod Drive System or Condensate System) and a combination of an ECCS pump and a safety/relief valve.

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is 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 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.

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 3.4.10.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 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 Specification contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic testing, and criticality, and also limits the maximum rate of change of reactor coolant temperature.

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 metal temperature represented in the P/T curves is for the beltline region of the vessel. The beltline region is the area of the vessel that surrounds the active fuel. Since there are no thermocouples in this section of the vessel the reactor coolant temperature is used to monitor the vessel metal temperature. The coolant temperature in the annulus space is assumed to be equal to the inside metal temperature. The inside metal temperature is used in the calculation to derive the P/T limit curves. Monitoring the reactor water cleanup (RWCU) or the reactor recirculation (RRC) coolant temperature allows the beltline metal temperature to be determined.

The RRC suction is taken from the annulus space between the vessel beltline region and the core shroud. This fluid temperature would represent the inside metal temperature for the beltline region.

(continued)

BASES

BACKGROUND
(continued)

The RWCU bottom head drain (which measures the fluid temperature) can be used if RRC is running. This allows mixing of the fluid in the bottom head area. The temperature measurement would be conservative due to the mixing of the annulus space fluid, feedwater, and control rod drive (CRD) return water.

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 American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The plant-specific reactor pressure vessel (RPV) materials surveillance program is replaced by the NRC approved BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (Ref. 11). The integrated surveillance program (ISP) meets the requirements of 10 CFR 50, Appendix H (Ref. 4) and addresses ASTM E 185 (Ref. 3) and Regulatory Guide 1.99 (Ref. 5). No capsules from the vessel are included in the ISP. The withdrawal of capsules for the plant-specific surveillance program is permanently deferred by participation in the ISP. Capsules from other plants will be removed and tested in accordance with the ISP implementation plan. The results from these tests will provide the necessary data to monitor embrittlement for the vessel. The operating P/T limit curves will be adjusted, as necessary, based on the evaluation of the test results provided by the ISP.

The P/T limit curves are composite curves established by superimposing limits derived from linear elastic fracture mechanics (LEFM) analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of

(continued)

BASES

BACKGROUND
(continued)

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. However, only the more restrictive of the two curves is used.

The P/T 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 leak 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. The 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. References 7 and 8 approved the curves and limits required by this Specification. 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 Reference 9.

(continued)

BASES (continued)

LCO

The elements of this LCO are:

- a. RCS pressure and temperature are within the limits specified in Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 and heatup and cooldown rates are $\leq 100^\circ\text{F}$ in any 1 hour period during RCS heatup, cooldown, and inservice leak and hydrostatic testing, and the RCS temperature change during inservice leak and hydrostatic testing is $\leq 20^\circ\text{F}$ in any 1 hour period when the RCS pressure and RCS temperature are not within the limits of Figure 3.4.11-2;
- b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is $\leq 145^\circ\text{F}$ during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;
- c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is $\leq 50^\circ\text{F}$ during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;
- d. RCS pressure and temperature are within the limits specified in Figure 3.4.11-3, prior to achieving criticality; and
- e. The reactor vessel flange and the head flange temperatures are $\geq 80^\circ\text{F}$ 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 controls the thermal gradient through the vessel wall and is used as input for calculating the heatup, cooldown, and inservice leak 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 LEM 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 existence, size, and orientation 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 while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by LEM 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, 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 vessel beltline.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 brought to 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 bringing the plant 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 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 LEFM analyses. The Required Action must be initiated without delay and continued until the limits are restored.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME 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 3.4.11.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. 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, 30 minutes permits assessment and correction of minor deviations. The limits of Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 are met when operation is to the right of the applicable limit curves.

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

This SR has been modified by a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.11.2

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. The limits of Figure 3.4.11-3 are met when operation is to the right of the limit curve.

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 3.4.11.3 and SR 3.4.11.4

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 loop (Ref. 10) are satisfied.

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.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.11.3 and SR 3.4.11.4 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.11.5 and SR 3.4.11.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels > 25% of RTP and with single loop flow rate > 10% of rated loop flow. Therefore, SR 3.4.11.5 and SR 3.4.11.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.11.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop can not be introduced into the remainder of the Reactor Coolant System.

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9

Limits on the reactor vessel flange and head flange temperatures 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.

The flange temperatures must be verified to be above the limits 30 minutes 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 RCS temperature $\leq 90^{\circ}\text{F}$, 30 minute checks of the flange

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9 (continued)

temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature $\leq 100^{\circ}\text{F}$, monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the specified limits.

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.11.7 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.11.8 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature $\leq 90^{\circ}\text{F}$ in MODE 4. SR 3.4.11.9 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature $\leq 100^{\circ}\text{F}$ 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 specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.
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. Letter from D.G. Eisenhut (NRC) to D.W. Mazur (WPPSS), "Issuance of Facility Operating License NPF-21 - WPPSS Nuclear Project No. 2," dated December 20, 1983.

(continued)

BASES

REFERENCES
(continued)

8. Letter from B.J. Benney (NRC) to J.V. Parrish (EN), "Columbia Generating Station - Issuance of Amendment Re: Reactor Coolant System (RCS) Pressure and Temperature Limits (TAC No. MC3591)," Issuance of Amendment No. 193, dated May 12, 2005.
 9. 10 CFR 50.36(c)(2)(ii).
 10. FSAR, Section 15.4.4.
 11. FSAR, Section 5.3.1.6.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Reactor Steam Dome Pressure

BASES

BACKGROUND

The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of Design Basis Accidents (DBAs) and transients.

APPLICABLE
SAFETY ANALYSES

The reactor steam dome pressure of ≤ 1035 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and 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 limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analyses of DBAs 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 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"). While the transient analyses assume an initial reactor steam dome pressure of 1020 psig, this value is more conservative than a higher reactor pressure, e.g., 1035 psig, with respect to the thermal limits attained during the transients. Therefore, the reactor steam dome pressure assumed in these analyses is bounded by the vessel overpressure protection analysis.

Reactor steam dome pressure satisfies the requirements of Criterion 2 of Reference 3.

LCO

The specified reactor steam dome pressure limit of ≤ 1035 psig ensures the plant is operated within the assumptions of the reactor overpressure analyses. Operation above the limit may result in a response more severe than analyzed.

(continued)

BASES (continued)

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 events that may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

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 15minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal.

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 3.4.12.1

Verification that reactor steam dome pressure is \leq 1035 psig ensures that the initial conditions of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES (continued)

- REFERENCES
1. FSAR, Section 5.2.2.
 2. FSAR, Chapters 15 and 15.F.
 3. 10 CFR 50.36(c)(2)(ii).
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) 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 is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. The ECCS also consists of 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 HPCS System.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously 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 HPCS pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the spray sparger above the core. If the break is small, HPCS will maintain coolant inventory, as well as vessel level, while the RCS is still pressurized. If HPCS fails, it is backed up by ADS in combination with LPCI and LPCS. In this event, the ADS timed sequence would be allowed to time out and open the selected safety/relief valves (SRVs), depressurizing the RCS and allowing the LPCI and LPCS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly, and the LPCI and LPCS systems cool the core.

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the Standby Service Water (SW) System. Depending on the location and

(continued)

BASES

BACKGROUND
(continued)

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.

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 subsystems.

The LPCS System (Ref. 1) consists of a motor driven pump, a spray sparger above the core, piping, and valves to transfer water from the suppression pool to the sparger. The LPCS System is designed to provide cooling to the reactor core when the reactor pressure is low. Upon receipt of an initiation signal, the LPCS pump is automatically started in approximately 9.5 seconds if normal AC power (from TR-S) is available; otherwise the pump is started immediately after AC power (from TR-B or the diesel generator (DG)) is available. When the RPV pressure drops sufficiently, LPCS flow to the RPV begins. A full flow test line is provided to route water to the suppression pool to allow testing of the LPCS System without spraying water into the RPV.

LPCI is an independent operating mode of the RHR System. There are three LPCI subsystems. Each LPCI subsystem (Ref. 2) consists of a motor driven pump, piping, and valves to transfer water from the suppression pool to the core. Each LPCI subsystem has its own suction and discharge piping and separate vessel nozzle that connects with the core shroud through internal piping. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, LPCI pump C is automatically started in approximately 9.5 seconds and A and B pumps in approximately 19.4 seconds if normal AC power (from TR-S) is available. Otherwise, C pump is started immediately after AC power (from TR-B or the DG) is available while A and B pumps are started after a 5 second delay). When the RPV pressure drops sufficiently, LPCI flow to the RPV begins. 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 core. A full flow test line is provided to route water to the suppression pool to allow testing of each LPCI pump without injecting water into the RPV.

(continued)

BASES

BACKGROUND
(continued)

The HPCS System (Ref. 3) consists of a single motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suction source to the sparger. Suction piping is provided from the CST and the suppression pool. Pump suction 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 the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCS System. The HPCS System is designed to provide core cooling over the full range of RPV pressures (0 psid to 1160 psid, vessel to drywell). Upon receipt of an initiation signal, the HPCS pump automatically starts (when AC power is available) and valves in the flow path begin to open. Since the HPCS System is designed to operate over the full range of expected RPV pressures, HPCS flow begins as soon as the necessary valves are open. A full flow test line is provided to route water to the CST to allow testing of the HPCS System during normal operation without spraying 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 or RPV pressure is greater than the LPCS or LPCI pump discharge pressures following system initiation. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the ECCS discharge line "keep fill" systems are designed to maintain all pump discharge lines filled with water.

The ADS (Ref. 4) consists of 7 of the 18 SRVs. It is designed to provide depressurization of the primary system during a small break LOCA if HPCS fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems, so that these subsystems can provide core cooling. Each ADS valve is supplied with pneumatic power from a cryogenic nitrogen supply system, which includes accumulators located in the drywell. In addition, during post LOCA conditions, if the normal, non-safety related, nitrogen supply becomes unavailable, the gas supply piping to the ADS function accumulators will automatically isolate from the cryogenic nitrogen supply. The ADS accumulator backup compressed gas

(continued)

BASES

BACKGROUND
(continued)

manifold subsystems will then provide a nominal pressure of 180 psig nitrogen from banks of high pressure compressed nitrogen cylinders. These cylinders provide a 30 day supply of nitrogen for the ADS function during a post LOCA condition.

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 References 5, 6, and 7. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 8), and the results of these analyses are 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 $\leq 2200^{\circ}\text{F}$;
- b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;
- c. Maximum hydrogen generation from zirconium water reaction is ≤ 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 large break LOCA, failure of ECCS subsystems in Division 1 (LPCS and LPCI A) or Division 2 (LPCI B and LPCI C) due to failure of its associated diesel generator is, in general, the most severe failure. For a small break LOCA, HPCS System failure is the most severe failure. The small break analysis also assumes two ADS valves are inoperable at the time of the accident. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of Reference 12.

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BASES (continued)

LCO

Each ECCS injection/spray subsystem and six ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS injection/spray subsystems are defined as the LPCS System and the three LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below 48 psig reactor steam dome pressure in MODE 3, 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 being realigned from or to the RHR shutdown cooling mode. 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.

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, the ADS function is not required when pressure is \leq 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCS subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCS subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE

(continued)

BASES

ACTIONS
(continued)

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 low pressure ECCS injection/spray subsystem is inoperable, 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. 13) that evaluated the impact on ECCS availability by assuming that 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 allowed outage times (i.e., Completion Times).

B.1 and B.2

If the HPCS System is inoperable, and the RCIC System is immediately verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS 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 injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other information, to determine if RCIC is out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be immediately verified and RCIC

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

is required to be OPERABLE, Condition D 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. A 14 day Completion Time is based on the results of a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hours Completion Time is based on a reliability study, as provided in Reference 13.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C 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 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.

E.1

The LCO requires six ADS valves to be OPERABLE to provide the ADS function. Reference 14 contains the results of an

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BASES

ACTIONS

E.1 (continued)

analysis that evaluated the effect of two ADS valves being out of service. This analysis showed that assuming a failure of the HPCS System, operation of only five 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. The 14 day Completion Time is based on a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one required ADS valve inoperable, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure (ADS) and low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

G.1 and G.2

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more required 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 ≤ 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

H.1

(continued)

When multiple ECCS subsystems are inoperable, as stated in Condition H, 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 flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The 31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

SR 3.5.1.2

Verifying the correct alignment for manual, 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 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 potentially capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.5.1.2 (continued)

alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

In MODE 3 with the reactor steam dome pressure less than 48 psig, 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 LPCI subsystems 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 being realigned from or to the RHR shutdown cooling mode. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than 48 psig, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

SR 3.5.1.3

Verification every 31 days that ADS accumulator backup compressed gas system average pressure in the required bottles is ≥ 2200 psig assures an adequate and OPERABLE air supply to the ADS valves. The minimum number of required bottles is 14 bottles in Division 1 and 17 in Division 2. The remote nitrogen cylinder connection in the DG corridor may be used to make up the minimum number of required bottles, provided the bottle(s) is properly installed to satisfy the seismic Category 1 restraint requirements and the bottle(s) capacity is greater than or equal to the capacity of the bottle being replaced. The nitrogen banks are sized to provide a 30 day supply of nitrogen for the ADS function. The ADS function is required to provide a flow path for alternate shutdown cooling. Alternate shutdown cooling is accomplished utilizing one RHR subsystem and the ADS to provide a path to the suppression pool for decay heat removal.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)SR 3.5.1.4

The performance requirements of the 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, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system pressure difference. For the LPCS and LPCI pumps the pressure difference is equivalent to that between the reactor and the suppression pool air volume. For the HPCS pump it is equivalent to the differential above the suction source (suppression pool or condensate storage tank). Under these conditions 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 LOCAs. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, 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. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.5.1.5 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month 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/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.

SR 3.5.1.6

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. This Surveillance also ensures the automatic alignment of the ADS accumulator backup compressed gas system on an actual or simulated ADS header pressure low signal. SR 3.5.1.7 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage (except for Division 3 which can be tested in any operational condition) 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 the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.6 (continued)

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.5.1.7. This also prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each required ADS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the SRV discharge lines. This is demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed, after the required pressure and flow are achieved, to perform this test. Adequate pressure at which this test is to be performed is 900 psig (consistent with the recommendations of the vendor). Adequate steam flow is represented by THERMAL POWER \geq 10% RTP. Reactor startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to reactor startup. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and flow are reached is sufficient to achieve stable conditions and provides adequate time to complete the SR. SR 3.5.1.6 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 24 months on a STAGGERED TEST BASIS ensures that both ADS trip system solenoids for each required ADS valve are alternately tested. The Frequency is based on the need to perform this Surveillance under the conditions that apply just prior to or during a startup from a plant outage.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.7 (continued)

Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is less than or equal to the maximum value assumed in the accident analysis. Response time testing acceptance criteria are included in Reference 15. This SR has been modified by a Note that allows the instrumentation portion of the response time to be excluded and therefore, it is not required to quantitatively measure the sensor response time to satisfy the requirement to verify ECCS RESPONSE TIME. This is acceptable since the instrumentation response time is a small part of the response time and can be qualitatively verified by other methods (Reference 16.) If the response time of the instrumentation is not quantitatively measured, the acceptance criteria must be reduced by a minimum of the time assumed for the instrumentation response in the design analyses, as supported by operating experience.

ECCS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience.

REFERENCES

1. FSAR, Section 6.3.2.2.3.
2. FSAR, Section 6.3.2.2.4.
3. FSAR, Section 6.3.2.2.1.
4. FSAR, Section 6.3.2.2.2.
5. FSAR, Section 15.6.6.
6. FSAR, Section 15.6.4.

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BASES

- REFERENCES
(continued)
7. FSAR, Section 15.6.5.
 8. 10 CFR 50, Appendix K.
 9. FSAR, Section 6.3.3.
 10. 10 CFR 50.46.
 11. FSAR, Section 6.3.3.3.
 12. 10 CFR 50.36(c)(2)(ii).
 13. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
 14. NEDC-32115P, Columbia Generating Station, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.
 15. Licensee Controlled Specifications Manual.
 16. NEDO 32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION
COOLING (RCIC) SYSTEM

B 3.5.2 ECCS - Shutdown

BASES

BACKGROUND A description of the High Pressure Core Spray (HPCS) System, Low Pressure Core Spray (LPCS) System, and low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS - Operating."

APPLICABLE SAFETY ANALYSES ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.

The ECCS satisfy Criterion 3 of Reference 2.

LCO Two ECCS injection/spray subsystems are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. The necessary portions of the Standby Service Water and HPCS Service Water Systems, as applicable, are also required to provide appropriate cooling to each required ECCS injection/spray subsystem.

One LPCI subsystem (A or B) may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the

(continued)

BASES

LCO
(continued)

LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncover.

APPLICABILITY

OPERABILITY of the ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 22 ft above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncover in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is < 150 psig, and the LPCS, HPCS, and LPCI subsystems can provide core cooling without any depressurization of the primary system.

ACTIONS

A.1 and B.1

If any one required ECCS injection/spray subsystem is inoperable, the required inoperable ECCS injection/spray subsystem must be restored to OPERABLE status within 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient RPV flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

Time for restoring the required ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the availability of one subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

C.1, C.2, D.1, D.2, and D.3

If both of the required ECCS injection/spray subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must be initiated immediately to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours. The 4 hour Completion Time to restore at least one ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

If at least one ECCS injection/spray subsystem is not restored to OPERABLE status within the 4 hour Completion Time, 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 is available in each secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. These administrative controls consist of

(continued)

BASES

ACTIONS

C.1, C.2, D.1, D.2, and D.3 (continued)

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). This may be performed 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 OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of 18 ft 6 inches required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pumps, recirculation volume (135,000 gallons consistent with the CST volume requirements described below), and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST (Ref. 5).

When the suppression pool level is < 18 ft 6 inches, the HPCS System 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 HPCS pump. Therefore, a verification that either the suppression pool water level is \geq 18 ft 6 inches or the HPCS System is aligned to take suction from the CST and the CST contains \geq 135,000 gallons of water. This volume of water is equivalent to a level of 14.8 ft in a single CST or 9.1 ft in each CST above the top of the suction line. This ensures that the HPCS System can supply makeup water to the RPV. Calculations that determine this water level are listed as References 3 and 4.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2 (continued)

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.5 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

SR 3.5.2.4

Verifying the correct alignment for manual, 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 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 valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

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 one LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.4 (continued)

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 being realigned from or to the RHR shutdown cooling mode. Because of the low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncover. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.

REFERENCES

1. FSAR, Section 6.3.3.4.
 2. 10 CFR 50.36(c)(2)(ii).
 3. E/I-02-91-1011.
 4. E/I-02-98-1002.
 5. TM 2092.
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) 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 RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) 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 head spray nozzle. 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 main steam line B, upstream of the inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, 165 psia to 1225 psia. 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 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 line "keep fill" system is designed to maintain the pump discharge line filled with water.

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 Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system satisfies Criterion 4 of Reference 3.

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.

APPLICABILITY

The RCIC System is required to be OPERABLE in 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 ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.

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.

(continued)

BASES

ACTIONS
(continued)A.1. and A.2

If the RCIC System is inoperable during MODE 1, or MODES 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCS 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 RPV pressure since the HPCS System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of the HPCS is therefore immediately verified when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if the HPCS is out of service for maintenance or other reasons. Verification does not require performing the Surveillances needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of the HPCS System cannot be immediately verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCS) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of 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. 4) that evaluated the impact on ECCS availability, assuming that 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 allowed outage times (AOTs). Because of the similar functions of the HPCS and RCIC, the AOTs (i.e., Completion Times) determined for the HPCS are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCS 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

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BASES

ACTIONS

B.1 and B.2 (continued)

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 flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC 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 involves verification that those valves capable of potentially being mispositioned are in the correct position. 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.5.3.2 (continued)

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least every 92 days. The Frequency of 31 days 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.

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 against a system head corresponding to reactor pressure is tested both at the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. 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. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Adequate reactor steam pressure to perform SR 3.5.3.3 is 935 psig and to perform SR 3.5.3.4 is 150 psig. Adequate steam flow to perform SR 3.5.3.3 is represented by THERMAL POWER \geq 10% RTP and to perform SR 3.5.3.4 is represented by turbine bypass valves \geq 10% open. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time 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 test 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

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BASES

SURVEILLANCE
REQUIREMENTSSR 3.5.3.3 and SR 3.5.3.4 (continued)

12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for the flow tests after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SRs.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply just prior to or during startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause the system 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. This Surveillance test also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.3.5 (continued)

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.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
 2. FSAR, Section 5.4.6.2.
 3. 10 CFR 50.36(c)(2)(ii).
 4. 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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