Niagara Mohawk

John H. Mueller
Senior Vice President and
Chief Nuclear Officer

Phone: 315.349.7907
Fax: 315.349.1321
e-mail: muellerj@nimo.com

December 14, 1999
NMP2L 1917

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

RE: Nine Mile Point Unit 2
Docket No. 50-410
NPF-69

Subject: ***Conversion of the Nine Mile Point Unit 2 Current Technical Specifications to the Improved Technical Specifications (TAC No. MA3822)***

Gentlemen:

Niagara Mohawk Power Corporation (NMPC) transmitted an Application for Amendment regarding the above subject by letter dated October 16, 1998 (NMP2L 1830). Subsequently, by letters dated March 26, 1999; May 10, 1999; May 18, 1999; June 16, 1999; September 2, 1999, and September 21, 1999, the Nuclear Regulatory Commission (NRC) requested additional information pertaining to the Application for Amendment. NMPC provided the requested additional information by letters dated May 10, 1999 (NMP2L 1866); June 15, 1999 (NMP2L 1872); July 30, 1999 (NMP2L 1881); August 2, 1999 (NMP2L 1883); August 11, 1999 (NMP2L 1885); August 16, 1999 (NMP2L 1886); August 19, 1999 (NMP2L 1888); August 27, 1999 (NMP2L 1893) and September 10, 1999 (NMP2L 1896). Additionally, meetings were held between the NRC Staff and NMPC on October 20 and 21, 1999 to discuss some of these issues further. The additional information provided by NMPC in these letters and during the meetings and subsequent telephone conversations included commitments to revise the Application for Amendment. Accordingly, the Enclosure to this letter provides the appropriate changes to our Application for Amendment regarding Volumes 1 through 11 of our October 16, 1998 and September 30, 1999 submittals. The specific changes are annotated by a vertical bar and a "C" in the right margin.

Attachment 1 of this letter provides a summary of the changes to the proposed Amendment. In addition, Attachment 2 provides the discard and insertion instructions pertaining to the integration of the proposed changes into our Application for Amendment dated October 16, 1998, as supplemented on September 30, 1999.

NMPC has determined that the revision of our proposed Amendment does not involve a significant hazards consideration. The evaluation supporting this determination is included in the enclosure to our letter dated October 16, 1998, as revised by the September 30, 1999 letter

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and the enclosure to this letter. In addition, the revision as discussed herein does not create a potential for a significant change in the types or a significant increase in the amounts of any effluents that may be released offsite, nor do the changes involve a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the revision of our proposed License Amendment meets the eligibility criteria for categorical exclusion as set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the revision to our proposed License Amendment is not required.

Pursuant to 10 CFR 50.91(b)(1), NMPC has provided a copy of the revision to this License Amendment application and the associated analysis regarding no significant hazards consideration to the appropriate state representative.

Sincerely,

John H. Mueller
Senior Vice President and
Chief Nuclear Officer

JHM/TWP/kap
Attachments 1 and 2
Enclosure

xc: Mr. H. J. Miller, NRC Regional Administrator, Region I
Mr. S. S. Bajwa, Section Chief PD-I, Section 1, NRR
Mr. G. K. Hunegs, NRC Senior Resident Inspector
Mr. D. S. Hood, Senior Project Manager, NRR
Mr. J. P. Spath
NYSERDA
286 Washington Avenue Ext.
Albany, NY 12203-6399
Records Management

ATTACHMENT 1

SUMMARY OF CHANGES

This attachment provides a brief summary of the changes in Revision C. The original Technical Specification amendment request (Revision A) was submitted to the NRC on October 16, 1998 and Revision B was submitted to the NRC on September 30, 1999.

The summary of the changes is provided in Chapter/Section order. Within each Chapter/Section, changes resulting from an NRC Request for Additional Information (RAI) or from verbal communications with the NRC are provided first, followed by addition changes identified by Niagara Mohawk Power Corporation (NMPC). Page removal and insert instructions have also been provided in Attachment 2 to facilitate updating the amendment request to include Revision C.

Chapter 1.0

1. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 have been made. These changes concern RAI 3.6.1.1-1. The changes affect the Current Technical Specification (CTS) markup for Improved Technical Specification (ITS) Chapter 1.0, pages 7 of 15 and 8 of 15, the Discussion of Changes (DOC) for ITS Chapter 1.0, DOC A.17 (page 5) and DOC LA.4 (pages 8 and 9).

Section 3.0

1. Changes have been made to be consistent with the approved Technical Specification Task Force (TSTF)-273, Rev. 2. These changes affect ITS Bases 3.0, pages B 3.0-8 and B 3.0-9, and the ISTS Bases markup pages B 3.0-9 and insert page B 3.0-9. The portion of the TSTF-273, Rev. 2 changes that affects Chapter 5.0 is described in the Chapter 5.0 changes below.

Section 3.1

1. An error was noted in the second Frequency for ITS Surveillance Requirement (SR) 3.1.7.9. This error has been corrected. This change affects ITS 3.1.7 page 3.1-22, the Discussion of Changes for ITS 3.1.7, DOC A.5 (page 2), the Improved Standard Technical Specification (ISTS) markup page 3.1-23, and the Justification for Deviations (JFD) to ITS 3.1.7, JFD 5 (page 1).

Section 3.3

1. The changes agreed upon by NMPC during a phone conversation with the NRC reviewer, with regard to providing additional information in the Bases describing the acceptability of the number of required Loss of Power channels, has been made. These changes affect ITS

3.3.8.1, Bases pages B 3.3-221 and B 3.3-222, and the ISTS Bases markup pages B 3.3-235 and B 3.3-236.

2. Typographical errors were noted in the clean-typed version of ITS 3.3.1.1 (the ISTS markup is correct). These have been corrected. These changes affect ITS 3.3.1.1, page 3.3-8.

3. ITS SR 3.3.2.1.4, parts a and b, have been combined into a single SR. The design of the logic is that the rod block monitor (RBM) is not bypassed when power is ≥ 30% Rated Thermal Power (RTP) and a peripheral control is not selected. With two separate parts, it could be interpreted that, for part a, if power is ≥ 30% RTP, the RBM cannot be bypassed even if a peripheral control rod is selected, and for part b, if a peripheral rod is selected, the RBM cannot be bypassed even if power is < 30% RTP. Combining the two parts corrects this problem. This change affects ITS 3.3.2.1, page 3.3-19 and Bases page B 3.3-51, the Discussion of Changes for ITS 3.3.2.1, DOC M.2 (page 2), the ISTS markup insert page B 3.3-19d, and the ISTS Bases markup insert page B 3.3-52m.

4. A typographical error was noted in Discussion of Changes for ITS 3.3.2.2, DOC M.1. This has been corrected. This change affects the Discussion of Changes for ITS 3.3.2.2, DOC M.1 (page 2).

5. ITS 3.3.4.2 ACTION D was modified to allow the pump breaker(s) to be removed from service in lieu of the ISTS requirement to remove the pump from service. However, it was noted that all places in the ITS Bases were not properly modified to reflect this change. This has been corrected. This change affects ITS 3.3.4.2 Bases page B 3.3-95 and the ISTS Bases markup page B 3.3-88.

6. ITS SRs 3.3.4.2.4 and 3.3.4.2.5 have been combined into a single SR. The design of the logic is that the low frequency motor generator will only trip on a steam dome pressure signal after 29 seconds if reactor power is > 5% RTP. With two separate SRs it could be interpreted that, for SR 3.3.4.2.4, if power is > 5% RTP, the trip cannot be bypassed for any length of time, and for SR 3.3.4.2.5, the trip cannot be bypassed for > 29 seconds, regardless of power level. Combining the two SRs corrects this problem. This change affects ITS 3.3.4.2, page 3.3-37 and Bases pages B 3.3-90, B 3.3-97, and B 3.3-98, the CTS markup for Specification 3.3.4.2, pages 2 of 5, 4 of 5, and 5 of 5, the Discussion of Changes for ITS 3.3.4.2, DOC A.4 (page 1), DOC M.2 (page 2), DOC LD.1 (page 3), and DOC LE.1 (page 3), the ISTS markup page 3.3-33, the Justification for Deviations to ITS 3.3.4.2, JFD 4 (page 1), and the ISTS Bases markup pages B 3.3-83, B 3.3-89, B 3.3-90, and insert page B 3.3-90.

7. A new Function has been added. The Area Temperature - Timer Function delays initiation of the RCIC Area Temperature - High Functions (ITS Table 3.3.6.1-1 Functions 3.e, 3.f, 3.g, 3.h, and 3.i). This timer was not included in the original submittal since NMPC intended to delete the timer from the system. Subsequently, it has been decided to maintain the timer, therefore, it is being added into the ITS. In addition, a typographical error was noted in the ITS Bases for Function 3.k (RCIC/RHR Steam Line Flow - Timer) (the ISTS Bases markup is correct). This has also been corrected. These changes affect ITS 3.3.6.1, page 3.3-62 and Bases pages B 3.3-151, B 3.3-169, B 3.3-170, B 3.3-171,

and B 3.3-180, the CTS markup for Specification 3.3.6.1, pages 5 of 19, 10 of 19, and 18 of 19, the Discussion of Changes for ITS 3.3.6.1, DOC M.3 (page 7), the ISTS markup pages 3.3-59 and insert page 3.3-59, the Justification for Deviations to ITS 3.3.6.1, JFD 4 (page 1), and the ISTS Bases markup pages B 3.3-141, B 3.3-156, insert page B 3.3-156, B 3.3-158, B 3.3-159, insert page B 3.3-159, B 3.3-168, and B 3.3-169.

8. Five additional Functions have been added to ITS Table 3.3.8.1-1 (Functions 1.b, 1.d, 1.e, 2.b, and 2.d). These Functions are Timer Functions which delay initiation of the 4.16 kV Emergency Bus Undervoltage - Loss of Voltage and 4.16 kV Emergency Bus Undervoltage - Degraded Voltage Functions for Divisions I, II, and III. Currently, the 4.16 kV Emergency Bus Undervoltage - Loss of Voltage and 4.16 kV Emergency Bus Undervoltage - Degraded Voltage Functions for Divisions I, II, and III actuate only after a time delay. An appropriate Surveillance Requirement to perform a CHANNEL CALIBRATION has also been added. This change affects ITS 3.3.8.1 page 3.3-78, the CTS markup for Specification 3.3.8.1, pages 2 of 8, 5 of 8, 6 of 8, and 7 of 8, the Discussion of Changes for ITS 3.3.8.1, DOC M.3 (page 3), DOC LD.1 (page 4), and DOC LE.1 (page 5), and the ISTS markup page 3.3-82.

9. A license amendment (Amendment 86) received subsequent to the original ITS submittal deleted the allowance to only test the electrical protection assemblies (EPAs) in MODE 4, since the Nine Mile Point Unit 2 (NMP2) design can accommodate testing of the EPAs without de-energizing the associated buses. The ITS is being modified to remove the allowance from the applicable SRs. This change affects ITS 3.3.8.2 page 3.3-82, ITS 3.3.8.3 page 3.3-84, ITS 3.3.8.2 Bases page B 3.3-232, ITS 3.3.8.3 Bases page B 3.3-239, the CTS markup for Specification 3.3.8.2, page 1 of 1, the CTS markup page for Specification 3.3.8.3, page 1 of 1, the ISTS markup for ITS 3.3.8.2, page 3.3-84, the Justification for Deviations to ITS 3.3.8.2, JFD 9 (page 3), the ISTS markup for ITS 3.3.8.3, insert page B 3.3-85b, the Justification for Deviations to ITS 3.3.8.3, JFD 6 (page 1), the ISTS Bases markup for ITS 3.3.8.2, page B 3.3-245, and the ISTS Bases markup for ITS 3.3.8.3, insert page B 3.3-246g.

Section 3.5

1. A error was noted in the CTS markup for Specification 3.5.2. The SR cross-reference from the CTS to the ITS was incorrect. This has been corrected. This change affects the CTS markup for Specification 3.5.2, page 2 of 5.

Section 3.6

1. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 have been made. These changes concern RAI 3.6.1.2-4. These changes affect ITS 3.6.1.2, Bases pages B 3.6-7 and B 3.6-12, and the ISTS Bases markup pages B 3.6-8 and B 3.6-12.

2. The change committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 has been made. This change concerns RAI 3.6.1.2-6. This change affects the Justification for Deviations to ITS Bases 3.6.1.2, JFD 8 (page 1).

3. The change committed to by NMPC in phone conversations with the NRC subsequent to the meetings with the NRC staff on October 20 and 21, 1999 has been made. This change concerns RAI 3.6.1.3-6. This change affects ITS 3.6.1.3 Bases page B 3.6-29, the CTS markup for Specification 3.6.1.3, page 2 of 14, the Discussion of Changes for ITS 3.6.1.3, DOC LA.5 (pages 5 and 6) and DOC L.7 (page 8), the ISTS Bases markup page B 3.6-29, and the No Significant Hazards Evaluation (NSHE) for ITS 3.6.1.3, NSHE L.7 (page 8).

4. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 have been made. These changes concern RAI 3.6.1.3-9 and also incorporate TSTF-45, Rev. 2 into ITS 3.6.4.2. These changes affect ITS 3.6.4.2 page 3.6-46, ITS 3.6.1.3 Bases pages B 3.6-25 and B 3.6-26, ITS 3.6.4.2 Bases pages B 3.6-83 and B 3.6-84, the CTS markup for Specification 3.6.4.2, page 4 of 4, the Discussion of Changes for ITS 3.6.4.2, DOC L.7 (pages 4 and 5), the ISTS 3.6.4.2 markup page 3.6-50, the ISTS 3.6.1.3 Bases markup page B 3.6-27, the ISTS 3.6.4.2 Bases markup page B 3.6-102, and the No Significant Hazards Evaluation for ITS 3.6.4.2, NSHE L.7 (pages 7 and 8).

5. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 and in phone conversations with the NRC subsequent to the meetings have been made. These changes concern RAI 3.6.1.3-14. These changes affect ITS 3.6.1.3, page 3.6-19 and Bases page B 3.6-31, the CTS markup for Specification 3.6.1.3, pages 6 of 14, 7 of 14, and 14 of 14, the Discussion of Changes for ITS 3.6.1.3, DOC LA.4 (page 5), the ISTS markup page 3.6-18, the Justification for Deviations to ITS 3.6.1.3, JFD 18 (page 4), the ISTS Bases markup page B 3.6-30 and B 3.6-31, and the Justification for Deviations to ITS Bases 3.6.1.3, JFD 17 (page 2) and JFD 18 (page 2).

6. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 and in phone conversations with the NRC subsequent to the meetings have been made. These changes concern RAI 3.6.1.3-21 and also similar changes into ITS 3.6.4.2. These changes affect ITS 3.6.1.3 Bases page B 3.6-16, ITS 3.6.4.2 Bases page B 3.6-80, ISTS 3.6.1.3 Bases markup page B 3.6-17, and ISTS 3.6.4.2 Bases markup page B 3.6-98.

7. The change committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 has been made. This change concerns RAI 3.6.1.4-1. This change affects ITS 3.6.1.4 Bases page B 3.6-32, ISTS Bases markup page B 3.6-33, and the Justification for Deviations to ITS 3.6.1.4, JFD 4 (page 1).

8. The change committed to by NMPC in phone conversations with the NRC subsequent to the meetings with the NRC staff on October 20 and 21, 1999 has been made. This change concerns RAI 3.6.1.6-4. This change affects ITS 3.6.1.6, page 3.6-25 and Bases page B 3.6-41, the CTS markup for Specification 3.6.1.6, page 1 of 1, the Discussion of Changes for ITS 3.6.1.6, DOC M.1 (page 2), and DOC L.2 (page 3), the ISTS markup page 3.6-

24, the Justification for Deviations to ITS 3.6.1.6, JFD 3 (page 1), and the ISTS Bases markup pages B 3.6-46, insert page B 3.6-46, and B 3.6-47.

9. The change committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 has been made. This change concerns RAI 3.6.2.1-8. This change affects ITS 3.6.2.1 Bases page B 3.6-49, the ISTS Bases markup page B 3.6-58, and the Justification for Deviations to ITS 3.6.2.1, JFD 7 (deleted from page 1).

10. The changes committed to by NMPC during the meetings with the NRC staff on October 20 and 21, 1999 have been made. These changes concern RAI 3.6.4.1-3. These changes affect ITS 3.6.4.1 Bases pages B 3.6-77 and B 3.6-78 and the ISTS Bases markup pages B 3.6-96 and insert page B 3.6-96.

11. The changes committed to by NMPC in phone conversations with the NRC subsequent to the meetings with the NRC staff on October 20 and 21, 1999 have been made. These changes concern RAIs 3.6.4.1-6, 3.6.4.2-7, and 3.6.4.3-4. These changes affect ITS 3.6.4.1 Bases pages B 3.6-75 and B 3.6-76, ITS 3.6.4.2 Bases page B 3.6-83, ITS 3.6.4.3 Bases page B 3.6-89, ISTS 3.6.4.1 Bases markup pages B 3.6-94, insert page B 3.6-94 (deleted) and B 3.6-95, the Justification for Deviations to ITS Bases 3.6.4.1, JFD 3 (page 1), the ISTS 3.6.4.2 Bases markup pages B 3.6-101 and insert page B 3.6-101 (deleted), and the ISTS 3.6.4.3 Bases markup pages B 3.6-107, insert page B 3.6-107 (deleted), B 3.6-108, and insert page B 3.6-108 (deleted).

12. ITS Limiting Condition for Operation (LCO) 3.6.1.3 requires each primary containment isolation valve (PCIV) to be Operable. The secondary containment bypass leakage limits, which are generally on a per valve basis and are specified in ITS Table 3.6.1.3-1, are part of this LCO, since an SR requires the secondary containment bypass leakage to be within limits (ITS SR 3.6.1.3.11). It was noted that not all valves listed in ITS Table 3.6.1.3-1 are PCIVs. Therefore, to avoid confusion if the leakage of one of the non-PCIVs listed in ITS Table 3.6.1.3-1 is not within limits, the LCO has been modified to include the non-PCIVs listed in ITS Table 3.6.1.3-1. This change affects ITS 3.6.1.3, page 3.6-9 and Bases pages B 3.6-14, B 3.6-15, and B 3.6-16, the CTS markup for Specification 3.6.1.3, page 6 of 14, the ISTS markup page 3.6-9, the Justification for Deviations to ITS 3.6.1.3, JFD 19 (page 4), and the ISTS Bases markup pages B 3.6-15, B 3.6-16, and B 3.6-17.

Section 3.7

1. NMPC noted that a JFD was not provided for some changes to ISTS 3.7.3 (ITS 3.7.2). The new JFD is consistent with the DOC that justified the change to the CTS (the change to the CTS was a beyond scope change identified by NMPC in the original ITS submittal). This change affects the Justification for Deviations to ITS 3.7.2, JFD 7 (pages 1 and 2).

2. NMPC noted that a JFD was not provided for some changes to ISTS 3.7.4 (ITS 3.7.3). The new JFD is consistent with the DOC that justified the change to the CTS (the change to the CTS was a beyond scope change identified by NMPC in the original ITS submittal). This change affects the Justification for Deviations to ITS 3.7.3, JFD 3 (page 1).

Section 3.8

1. The change agreed upon by NMPC during a phone conversation with the NRC reviewer has been made. This change concerns RAI 3.8.1-02. This change affects the CTS markup for Specification 3.8.1, pages 4 of 12 and 12 of 12, the Discussion of Changes for ITS 3.8.1, DOC LA.2 (page 8) and DOC L.23 (pages 18 and 19), and the No Significant Hazards Evaluation for ITS 3.8.1, NSHE L.23 (page 25).

2. The change agreed upon by NMPC during a phone conversation with the NRC reviewer has been made. This change concerns RAI 3.8.1-03. This change affects ITS 3.8.1, page 3.8-7 and Bases page B 3.8-19, the CTS markup for Specification 3.8.1, page 5 of 12, the Discussion of Changes for ITS 3.8.1, DOC L.6 (page 12), the ISTS markup page 3.8-7, the ISTS Bases markup page B 3.8-20, and the No Significant Hazards Evaluation, NSHE L.6 (page 6).

3. The changes agreed upon by NMPC during a phone conversation with the NRC reviewer have been made. These changes concern RAIs 3.8.1-06, 3.8.1-09, and 3.8.1-17. These changes affect ITS 3.8.1 pages 3.8-10, 3.8-11, and 3.8-17, the CTS markup for Specification 3.8.1, pages 7 of 12 and 9 of 12, the Discussion of Changes for ITS 3.8.1, DOC M.11 (page 6) and DOC LA.7 (page 9), the ISTS markup page 3.8-11, 3.8-12, and 3.8-17, and the Justification for Deviations to ITS 3.8.1, JFD 17 (page 4).

4. The change agreed upon by NMPC during a phone conversation with the NRC reviewer has been made. This change concerns RAI 3.8.1-07. This change affects ITS 3.8.1, page 3.8-16 and Bases page B 3.8-29, the CTS markup for Specification 3.8.1, page 11 of 12, the Discussion of Changes for ITS 3.8.1, DOC L.24 (pages 19 and 20), the ISTS markup page 3.8-16, the Justification for Deviations to ITS 3.8.1, JFD 18 (pages 4 and 5), the ISTS Bases markup pages B 3.8-31 and insert page B 3.8-31, and the No Significant Hazards Evaluation for ITS 3.8.1, NSHE L.24 (page 26).

5. The CTS markup for ITS 3.8.4 (CTS 4.8.2.1.d.2), page 3 of 5, was annotated with the current rates to be used for the battery service tests. The proposed current rates were consistent with the DC battery load profiles in the Updated Safety Analysis Report (USAR) at the time of the original submittal. A USAR update was made to the NMP2 USAR subsequent to the original ITS submittal. This change modified the Division 1 DC battery load profile. This change was noted by both NMPC and the NRC reviewer, and the proper values (consistent with the most current USAR revision) have been verbally communicated to the NRC reviewer. This change corrects the CTS markup (consistent with the values provided to the NRC reviewer). This change affects the CTS markup for ITS 3.8.4, page 3 of 5.

6. A typographical error was noted in the ITS 3.8.1 Bases. This error has been corrected. This change affects ITS 3.8.1 Bases page B 3.8-26 and ISTS Bases markup page B 3.8-28.

7. A typographical error was noted in the ITS 3.8.8 Bases. This error has been corrected. This change affects ITS 3.8.8 Bases page B 3.8-77 and ISTS Bases markup page B 3.8-84.

8. A typographical error was noted in the Table that lists the required electrical power distribution buses (ITS Table B 3.8.8-1). The Table inadvertently listed the 120 VAC uninterruptible panels in the AC buses section also (i.e., they were listed in two locations, and have been deleted from the inappropriate location). This change affects ITS 3.8.8 Bases page B 3.8-84 and ISTS Bases markup insert page B 3.8-90.

Chapter 5.0

1. Changes have been made to be consistent with the approved TSTF-273, Rev. 2. These changes affect ITS 5.5.11 page 5.0-16 and the ISTS markup pages 5.0-16 and 5.0-17. The portion of the TSTF-273, Rev. 2 changes that affects Section 3.0 is described in the Section 3.0 changes above.

ATTACHMENT 2

DISCARD AND INSERTION INSTRUCTIONS

VOLUME 1	
CHAPTER 1.0	
DISCARD	INSERT
CTS markup for Chapter 1.0 pages 7 of 15 and 8 of 15	CTS markup for Chapter 1.0 pages 7 of 15 and 8 of 15
Discussion of Changes for ITS Chapter 1.0 pages 5 through 9	Discussion of Changes for ITS Chapter 1.0 pages 5 through 10
SECTION 3.0	
ITS Bases pages B 3.0-8 through B 3.0-15	ITS Bases pages B 3.0-8 through B 3.0-16
ISTS Bases markup page B 3.0-9	ISTS Bases markup page B 3.0-9 and insert page B 3.0-9

VOLUME 2	
SECTION 3.1	
DISCARD	INSERT
ITS page 3.1-22	ITS page 3.1-22
Discussion of Changes for ITS 3.1.7 page 2	Discussion of Changes for ITS 3.1.7 page 2
ISTS markup page 3.1-23	ISTS markup page 3.1-23
Justification for Deviations to ITS 3.1.7 page 1	Justification for Deviations to ITS 3.1.7 page 1

VOLUME 3	
SECTION 3.3: ITS, Bases, and CTS Markup/DOCs	
DISCARD	INSERT
ITS page 3.3-8	ITS page 3.3-8
ITS page 3.3-19	ITS page 3.3-19
ITS page 3.3-37	ITS page 3.3-37
ITS page 3.3-62	ITS page 3.3-62
ITS page 3.3-78	ITS page 3.3-78
ITS page 3.3-82	ITS page 3.3-82
ITS page 3.3-84	ITS page 3.3-84
ITS Bases page B 3.3-51	ITS Bases page B 3.3-51
ITS Bases page B 3.3-90	ITS Bases page B 3.3-90
ITS Bases page B 3.3-95	ITS Bases page B 3.3-95
ITS Bases pages B 3.3-97 through B 3.3-241	ITS Bases pages B 3.3-97 through B 3.3-240
Discussion of Changes for ITS 3.3.2.1 page 2	Discussion of Changes for ITS 3.3.2.1 page 2
Discussion of Changes for ITS 3.3.2.2 page 2	Discussion of Changes for ITS 3.3.2.2 page 2
CTS markup for Specification 3.3.4.2 page 2 of 5	CTS markup for Specification 3.3.4.2 page 2 of 5
CTS markup for Specification 3.3.4.2 pages 4 of 5 and 5 of 5	CTS markup for Specification 3.3.4.2 pages 4 of 5 and 5 of 5
Discussion of Changes for ITS 3.3.4.2 pages 1 through 3	Discussion of Changes for ITS 3.3.4.2 pages 1 through 3
CTS markup for Specification 3.3.6.1 page 5 of 19	CTS markup for Specification 3.3.6.1 page 5 of 19
CTS markup for Specification 3.3.6.1 page 10 of 19	CTS markup for Specification 3.3.6.1 page 10 of 19
CTS markup for Specification 3.3.6.1 page 18 of 19	CTS markup for Specification 3.3.6.1 page 18 of 19
Discussion of Changes for ITS 3.3.6.1 page 7	Discussion of Changes for ITS 3.3.6.1 page 7
CTS markup for Specification 3.3.8.1 page 2 of 8	CTS markup for Specification 3.3.8.1 page 2 of 8
CTS markup for Specification 3.3.8.1 pages 5 of 8 through 7 of 8	CTS markup for Specification 3.3.8.1 pages 5 of 8 through 7 of 8
Discussion of Changes for ITS 3.3.8.1 pages 3 through 5	Discussion of Changes for ITS 3.3.8.1 pages 3 through 5
CTS markup for Specification 3.3.8.2 page 1 of 1	CTS markup for Specification 3.3.8.2 page 1 of 1
CTS markup for Specification 3.3.8.3 page 1 of 1	CTS markup for Specification 3.3.8.3 page 1 of 1

VOLUME 4	
SECTION 3.3: ISTS/JFDs, ISTS Bases/JFDs, and NSHE	
DISCARD	INSERT
ISTS markup insert page 3.3-19d	ISTS markup insert page 3.3-19d
ISTS markup page 3.3-33	ISTS markup page 3.3-33
Justification for Deviations to ITS 3.3.4.2 page 1	Justification for Deviations to ITS 3.3.4.2 page 1
ISTS markup page 3.3-59 and insert page 3.3-59	ISTS markup page 3.3-59 and insert page 3.3-59
Justification for Deviations to ITS 3.3.6.1 page 1	Justification for Deviations to ITS 3.3.6.1 page 1
ISTS markup page 3.3-82	ISTS markup page 3.3-82
ISTS markup page 3.3-84	ISTS markup page 3.3-84
Justification for Deviations to ITS 3.3.8.2 page 3	Justification for Deviations to ITS 3.3.8.2 page 3
ISTS markup insert page 3.3-85b	ISTS markup insert page 3.3-85b
Justification for Deviations to ITS 3.3.8.3 page 1	Justification for Deviations to ITS 3.3.8.3 page 1
ISTS Bases markup page B 3.3-52m	ISTS Bases markup page B 3.3-52m
ISTS Bases markup page B 3.3-83	ISTS Bases markup page B 3.3-83
ISTS Bases markup pages B 3.3-88 and B 3.3-89	ISTS Bases markup pages B 3.3-88 and B 3.3-89
ISTS Bases markup page B.3.3-90 and insert page B 3.3-90	ISTS Bases markup page B 3.3.90 and insert page B 3.3-90
ISTS Bases markup page B 3.3-141	ISTS Bases markup page B 3.3-141
ISTS Bases markup page B 3.3-156	ISTS Bases markup page B 3.3-156 and insert page B 3.3-156
ISTS Bases markup page B 3.3-158	ISTS Bases markup page B 3.3-158
ISTS Bases markup page B 3.3-159 and insert page B 3.3-159	ISTS Bases markup page B 3.3-159 and insert page B 3.3-159
ISTS Bases markup page B 3.3-168	ISTS Bases markup page B 3.3-168
ISTS Bases markup page B 3.3-169	ISTS Bases markup page B 3.3-169
ISTS Bases markup pages B 3.3-235 and B 3.3-236	ISTS Bases markup pages B 3.3-235 and B 3.3-236
ISTS Bases markup page B 3.3-245	ISTS Bases markup page B 3.3-245
ISTS Bases markup insert page B 3.3-246g	ISTS Bases markup insert page B 3.3-246g

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DISCARD	INSERT
ITS page 3.6-9	ITS page 3.6-9
ITS page 3.6-19	ITS page 3.6-19
ITS page 3.6-25	ITS page 3.6-25
ITS page 3.6-46	ITS page 3.6-46
ITS Bases page B 3.6-7	ITS Bases page B 3.6-7
ITS Bases page B 3.6-12	ITS Bases page B 3.6-12
ITS Bases pages B 3.6-14 through B 3.6-32	ITS Bases pages B 3.6-14 through B 3.6-32
ITS Bases page B 3.6-41	ITS Bases page B 3.6-41
ITS Bases pages B 3.6-49 through B 3.6-52	ITS Bases pages B 3.6-49 through B 3.6-52
ITS Bases pages B 3.6-75 through B 3.6-78	ITS Bases pages B 3.6-75 through B 3.6-78
ITS Bases page B 3.6-80	ITS Bases page B 3.6-80
ITS Bases pages B 3.6-83 through B 3.6-85	ITS Bases pages B 3.6-83 through B 3.6-85
ITS Bases pages B 3.6-89 through B 3.6-91	ITS Bases pages B 3.6-89 through B 3.6-91
CTS markup for Specification 3.6.1.3 page 2 of 14	CTS markup for Specification 3.6.1.3 page 2 of 14
CTS markup for Specification 3.6.1.3 pages 6 of 14 and 7 of 14	CTS markup for Specification 3.6.1.3 pages 6 of 14 and 7 of 14
CTS markup for Specification 3.6.1.3 page 14 of 14	CTS markup for Specification 3.6.1.3 page 14 of 14
Discussion of Changes for ITS 3.6.1.3 pages 5 through 14	Discussion of Changes for ITS 3.6.1.3 pages 5 through 14
CTS markup for Specification 3.6.1.6 page 1 of 1	CTS markup for Specification 3.6.1.6 page 1 of 1
Discussion of Changes for ITS 3.6.1.6 pages 2 and 3	Discussion of Changes for ITS 3.6.1.6 pages 2 and 3
CTS markup for Specification 3.6.4.2 page 4 of 4	CTS markup for Specification 3.6.4.2 page 4 of 4
Discussion of Changes for ITS 3.6.4.2 page 4	Discussion of Changes for ITS 3.6.4.2 pages 4 and 5

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DISCARD	INSERT
ISTS markup page 3.6-9	ISTS markup page 3.6-9
ISTS markup page 3.6-18	ISTS markup page 3.6-18
Justification for Deviations to ITS 3.6.1.3 page 4	Justification for Deviations to ITS 3.6.1.3 page 4
ISTS markup page 3.6-24	ISTS markup page 3.6-24
Justification for Deviations to ITS 3.6.1.6 page 1	Justification for Deviations to ITS 3.6.1.6 page 1
ISTS markup page 3.6-50	ISTS markup page 3.6-50
ISTS Bases markup page B 3.6-8	ISTS Bases markup page B 3.6-8
ISTS Bases markup page B 3.6-12	ISTS Bases markup page B 3.6-12
Justification for Deviations to ITS Bases 3.6.1.2 page 1	Justification for Deviations to ITS Bases 3.6.1.2 page 1
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ISTS Bases markup page B 3.6-27	ISTS Bases markup page B 3.6-27
ISTS Bases markup pages B 3.6-29	ISTS Bases markup pages B 3.6-29
ISTS Bases markup pages B 3.6-30 and B 3.6-31	ISTS Bases markup pages B 3.6-30 and B 3.6-31
Justification for Deviations to ITS Bases 3.6.1.3 page 2	Justification for Deviations to ITS Bases 3.6.1.3 page 2
ISTS Bases markup page B 3.6-33	ISTS Bases markup page B 3.6-33
Justification for Deviations to ITS Bases 3.6.1.4 page 1	Justification for Deviations to ITS Bases 3.6.1.4 page 1
ISTS Bases markup page B 3.6-46	ISTS Bases markup page B 3.6-46 and insert page B 3.6-46
ISTS Bases markup page B 3.6-47	ISTS Bases markup page B 3.6-47
ISTS Bases markup page B 3.6-58	ISTS Bases markup page B 3.6-58
Justification for Deviations to ITS Bases 3.6.2.1 page 1	Justification for Deviations to ITS Bases 3.6.2.1 page 1
ISTS Bases markup page B 3.6-94 and insert page B 3.6-94	ISTS Bases markup page B 3.6-94
ISTS Bases markup page B 3.6-95	ISTS Bases markup page B 3.6-95

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ISTS Bases markup page B 3.6-96	ISTS Bases markup page B 3.6-96 and insert page B 3.6-96
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ISTS Bases markup page B 3.6-98	ISTS Bases markup page B 3.6-98
ISTS Bases markup page B 3.6-101 and insert page B 3.6-101	ISTS Bases markup page B 3.6-101
ISTS Bases markup page B 3.6-102	ISTS Bases markup page B 3.6-102
ISTS Bases markup page B 3.6-107 and insert page B 3.6-107	ISTS Bases markup page B 3.6-107
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SECTION 3.7	
DISCARD	INSERT
Justification for Deviations to ITS 3.7.2 page 1	Justification for Deviations to ITS 3.7.2 pages 1 and 2
Justification for Deviations to ITS 3.7.3 page 1	Justification for Deviations to ITS 3.7.3 page 1

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DISCARD	INSERT
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ITS pages 3.8-10 and 3.8-11	ITS pages 3.8-10 and 3.8-11
ITS pages 3.8-16 and 3.8-17	ITS pages 3.8-16 and 3.8-17
ITS Bases pages B 3.8-16 through B 3.8-29	ITS Bases pages B 3.8-16 through B 3.8-29
ITS Bases page B 3.8-77	ITS Bases page B 3.8-77
ITS Bases page B 3.8-84	ITS Bases page B 3.8-84
CTS markup for Specification 3.8.1 pages 4 of 12 and 5 of 12	CTS markup for Specification 3.8.1 pages 4 of 12 and 5 of 12
CTS markup for Specification 3.8.1 page 7 of 12	CTS markup for Specification 3.8.1 page 7 of 12
CTS markup for Specification 3.8.1 page 9 of 12	CTS markup for Specification 3.8.1 page 9 of 12
CTS markup for Specification 3.8.1 pages 11 of 12 and 12 of 12	CTS markup for Specification 3.8.1 pages 11 of 12 and 12 of 12
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CTS markup for Specification 3.8.4 page 3 of 5	CTS markup for Specification 3.8.4 page 3 of 5
ISTS markup page 3.8-7	ISTS markup page 3.8-7
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ISTS markup pages 3.8-16 and 3.8-17	ISTS markup pages 3.8-16 and 3.8-17
Justification for Deviations to ITS 3.8.1 page 4	Justification for Deviations to ITS 3.8.1 pages 4 and 5
ISTS Bases markup page B 3.8-20	ISTS Bases markup page B 3.8-20
ISTS Bases markup page B 3.8-28	ISTS Bases markup page B 3.8-28
ISTS Bases markup page B 3.8-31	ISTS Bases markup page B 3.8-31 and insert page B 3.8-31
ISTS Bases markup page B 3.8-84	ISTS Bases markup page B 3.8-84
ISTS Bases markup insert page B 3.8-90	ISTS Bases markup insert page B 3.8-90
No Significant Hazards Evaluation for ITS 3.8.1 page 6	No Significant Hazards Evaluation for ITS 3.8.1 page 6
	No Significant Hazards Evaluation for ITS 3.8.1 pages 25 and 26

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DISCARD	INSERT
ITS pages 5.0-16 through 5.0-24	ITS pages 5.0-16 through 5.0-25
ISTS markup pages 5.0-16 and 5.0-17	ISTS markup pages 5.0-16 and 5.0-17

ENCLOSURE

A.1

DEFINITIONS

MILK SAMPLING LOCATION

1.24 A MILK SAMPLING LOCATION is a location where 10 or more head of milk animals are available for the collection of milk samples.

A.2

MINIMUM CRITICAL POWER RATIO (MCPR)

1.25 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be the smallest critical power ratio (CPR) which exists in the core for each class of fuel.

A.1 Insert definition of CPR from page 1-2

OFFSITE DOSE CALCULATION MANUAL

1.26 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the current methodology and parameters used in the calculation of offsite doses that result from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the environmental radiological monitoring program.

A.6 A.14 Move to Section 5.5

OPERABLE - OPERABILITY

1.27 A system, subsystem, division, train, component, or device shall be OPERABLE or safety have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

A.1 A.15 normal or emergency

OPERATIONAL CONDITION - CONDITION (MODE)

1.28 An OPERATIONAL CONDITION, i.e., CONDITION, shall correspond to any one inclusive combination of mode switch position, and average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

A.1 A.16

PHYSICS TESTS

1.29 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation, and (a) described in Chapter 14 of the FSAR, (b) authorized under the provisions of 10 CFR 50.59, or (c) otherwise approved by the Commission. These tests are: Initial Test Program Nuclear Regulatory

A.1 A.9

PRESSURE BOUNDARY LEAKAGE

1.30 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall, or vessel wall.

A.1 RCS

PRIMARY CONTAINMENT INTEGRITY

1.31 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

A.4 A.17

Chapter 1.0

A.1

DEFINITIONS

PRIMARY CONTAINMENT INTEGRITY

1.31 (Continued)

1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

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

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression pool is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

A.17

A.4 | C

PROCESS CONTROL PROGRAM

A.18 moved to chapter 5.0

1.32 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formula sampling, analyses, tests, and determinations to be made to ensure that the processing and packaging of radioactive wastes, based on demonstrated processing of actual or simulated wet or liquid wastes, will be accomplished in such a way as to assure compliance with 10 CFR 20, 10 CFR 61, 10 CFR 71, and Federal and State regulations and other requirements governing the transport and disposal of radioactive waste.

PURGE - PURGING

A.2

1.33 PURGE and PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER (RTP)

1.34 RATED THERMAL POWER (RTP) shall be a total reactor core heat transfer rate to the reactor coolant of 3467 MWt.

A.1

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

1.35 The RPS REACTOR PROTECTION SYSTEM RESPONSE TIME shall be that the time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor

A.1

Page 8 of 15

ADMINISTRATIVE (continued)

A.17 The definitions of PRIMARY CONTAINMENT INTEGRITY and SECONDARY CONTAINMENT INTEGRITY have been deleted because these definitions duplicate requirements that are appropriately contained in Specifications. This was also done because of the confusion associated with these definitions compared to their use in their respective LCOs. Some of the details of the Primary Containment definition are relocated to ITS 3.6.1.1 Bases (refer to Discussion of Change LA.4 below for detailed discussion). The change is editorial in that all the requirements are specifically addressed in the LCOs for the Primary Containment and Secondary Containment, along with the remainder of the LCOs in the Containment Systems Section. Specifically:

- CTS 1.31.a.1. and 2: adequately addressed by ITS LCO 3.6.1.3 and associated SRs 3.6.1.3.2, 3.6.1.3.3, and 3.6.1.3.8.
- CTS 1.31.b and f: adequately addressed by the Primary Leakage Rate Testing Requirements of ITS SR 3.6.1.1.1 Type A leakage test.
- CTS 1.31.c: addressed by ITS LCO 3.6.1.2.
- CTS 1.31.d: addressed by ITS LCO 3.6.1.1 and SRs 3.6.1.3.6, 3.6.1.3.11, 3.6.1.3.12, and 3.6.1.3.13.
- CTS 1.31.e: addressed by ITS LCOs 3.6.1.1, 3.6.2.1, and 3.6.2.2.
- CTS 1.38.a.1. and 2: adequately addressed by ITS LCO 3.6.4.2 and associated SRs 3.6.4.2.1 and 3.6.4.2.3.
- CTS 1.38.b and e: "sealing" requirements for hatches and sealing mechanisms are adequately addressed by the leakage testing requirements of ITS SR 3.6.4.1.5.
- CTS 1.38.b: closed hatch requirements are addressed by ITS SR 3.6.4.1.2.
- CTS 1.38.c: addressed by ITS LCO 3.6.4.3.
- CTS 1.38.d: addressed by ITS SR 3.6.4.1.3.
- CTS 1.38.f: addressed by ITS SR 3.6.4.1.1.

A.18 The definition of PROCESS CONTROL PROGRAM has been moved to the Administrative Controls Chapter (Chapter 5.0). Any technical changes to this definition is addressed in the Discussion of Changes for CTS: 6.13.

A.19 The following sections are added to the Technical Specifications. These additions aid in the understanding and use of the new format and presentation style. Some conventions in applying the Technical Specifications to unusual situations have been the subject of debate and varying interpretation between the licensee and the NRC Staff. Because the guidance in these proposed sections establishes positions not previously formalized, the guidance is considered administrative. These sections are consistent with the BWR STS, NUREG-1434, Rev. 1. The added sections are as follows:

ADMINISTRATIVE

A.19 (cont'd) SECTION 1.2 - LOGIC CONNECTORS

Section 1.2 provides specific examples of the logical connectors "AND" and "OR" and the numbering sequence associated with their use.

SECTION 1.3 - COMPLETION TIMES

Section 1.3 provides proper use and interpretation of Completion Times. The Section also provides specific examples that aid the user in understanding Completion Times.

SECTION 1.4 - FREQUENCY

Section 1.4 provides proper use and interpretation of the Surveillance Frequency. The Section also provides specific examples that aid the user in understanding Surveillance Frequency.

A.20 The definition of SHUTDOWN MARGIN has been modified to address stuck control rods. This is consistent with the NMP2 CTS requirement found in CTS 4.1.1.c to account for the worth of a stuck control rod. The movement of this requirement to the SDM definition is considered to be editorial.

A.21 The definition of STAGGERED TEST BASIS has been modified to be consistent with its usage throughout the NMP2 ITS. The intent of the frequency of testing components on a STAGGERED TEST BASIS is not changed. The revised definition allows the minimum Surveillance interval to be specified in the Surveillance Requirements' Frequency column of the applicable LCOs, independent of the number of subsystems. This represents an editorial preference to the current TS presentation.

A.22 CTS Table 1.2, footnotes *, **, and †, have been moved to LCO requirements in the Special Operations Section (currently titled "Special Test Exceptions"). Any technical changes to these footnotes are addressed in the Discussion of Changes for ITS: 3.10.2, ITS: 3.10.3, and ITS: 3.10.4.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS Table 1.2 has been modified by a) the addition of the head closure status (proposed footnote (a)) to Conditions (MODES) 3 and 4, b) the addition of the refuel mode switch position to MODE 2 (including footnote (a)), and c) the deletion of the coolant temperature limit of MODE 5. These changes address plant conditions not previously satisfying a defined MODE, or satisfying more than one MODE. The intent of these changes is to provide clarity and completeness in avoiding any potential misinterpretation, and as such could be considered administrative. However, since the changes eliminate the potential to interpret certain plant conditions such that no MODE, or a less restrictive MODE would exist, this change is discussed and justified as a "more restrictive" change. Specifically:

- STARTUP MODE will now include the mode switch position of "Refuel" when the head bolts are fully tensioned (footnote "(a)"). This is currently a plant condition which has no corresponding MODE and could therefore be incorrectly interpreted as not requiring the application of the majority of Technical Specifications. By defining this plant condition as STARTUP MODE, sufficiently conservative restrictions will be applied by the applicable LCOs.

- Clarifying the shutdown MODES with a new footnote stating "all reactor vessel head bolts fully tensioned" eliminates the overlap in defined MODES when the mode switch is in "Shutdown" position: with the vessel head detensioned, both the definition of REFUEL as well as COLD SHUTDOWN could apply. It is not the intent of the Technical Specification to allow an option of whether to apply REFUEL applicable LCOs or to apply COLD SHUTDOWN applicable LCOs. This change precludes an unacceptable interpretation.

- The definition of REFUEL would cease to be applicable when average coolant temperature exceeded 140° F. With the mode switch in "Refuel" a plant condition which has no corresponding MODE exists. This could therefore be incorrectly interpreted as not requiring the application of the majority of Technical Specifications. By defining the REFUEL MODE as including plant conditions with no specific coolant temperature range, sufficiently conservative restrictions will be applied by the applicable LCOs during all fueled conditions with the vessel head bolts detensioned.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The definition of FRACTION OF RATED POWER (FRTP) in CTS 1.15 is used only in one proposed Specification (ITS 3.2.3). As such, the definition has been moved to the Bases for ITS 3.2.3, Average Power Range Monitor (APRM) Gain and Setpoint. The requirements of ITS 3.2.3 and the associated Surveillance Requirements are sufficient to ensure APRM gains and setpoints are appropriately controlled. The information in the definition of FRTP is not required in the ITS for proper interpretation of the Specification. However, for additional clarity, the definition of FRTP has been included in the Bases. This is consistent with the BWR STS, NUREG-1434, Rev. 1. Therefore, the relocated definition is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.2 The definition of ROD DENSITY in CTS 1.37 is used in only one proposed Specification (ITS 3.1.2). As such, the definition has been moved to the Bases for ITS 3.1.2, "Reactivity Anomalies." The requirements of ITS 3.1.2 and the associated Surviellance Requirements are sufficient to ensure the reactivity anomaly is appropriately controlled and determined. The information in the definition of ROD DENSITY is not required in the ITS for proper interpretation. However, for additional clarity, the definition of rod density has been included in the Bases. Therefore, the relocated definition is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.3 The definition of SOURCE CHECK in CTS 1.42 is used in only one proposed Specification (ITS 3.4.7). As such, the definition has been moved to the Bases for ITS 3.4.7, "RCS Leakage Detection System." The requirements of ITS 3.4.7 and the associated Surveillance Requirements are sufficient to ensure a source check is correctly performed. The information in the definition of SOURCE CHECK is not required in the ITS for proper interpretation. However, for additional clarity, the definition of source check has been included in the Bases. Therefore, the relocated definition is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.4 The CTS definition for Primary Containment Integrity is deleted because this definition duplicates requirements that are appropriately contained in other Specifications (refer to Discussion of Change A.17 above for detailed

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.4 (cont'd) discussion). However, CTS definition 1.31.a, b, c, and f are relocated to ITS 3.6.1.1 Bases, stating the necessity for these requirements as they relate to maintaining a leak-tight containment barrier. This is acceptable since these details do not impact the requirements to maintain the primary containment (including associated support systems and components) Operable. Therefore, the relocated portions of the definition are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS. C

"Specific"

L.1 The proposed CHANNEL FUNCTIONAL TEST (CFT) definition combining analog and bistable channel requirements results in an allowance for the bistable channel test signal to be injected "as close to the sensor as practicable" in lieu of "into the sensor," as is currently required by the CFT definition. Also, the proposed definition of LOGIC SYSTEM FUNCTIONAL TEST (LSFT) allows the signal to be injected "as close to the sensor as practicable" in lieu of "from the sensor," as is currently required by the LSFT definition. Injecting a signal at the sensor would in some cases involve significantly increased probabilities of initiating undesired circuits during the test since several logic channels are often associated with a particular sensor. Performing the test by injection of a signal at the sensor requires jumpering of the other logic channels to prevent their initiation during the test, or increases the scope of the test to include multiple tests of the other logic channels. Either method significantly increases the difficulty of performing the surveillance. Allowing initiation of the signal close to the sensor provides a complete test of the logic channel while significantly reducing this probability of undesired initiation.

L.2 CTS 1.10 states that the DOSE EQUIVALENT I-131 is calculated using the thyroid dose conversion factors found in Table III of TID 14844, "Calculation of Distance Factors for Power and Test Reactor Sites." The ITS allows DOSE EQUIVALENT I-131 to be calculated using any one of three thyroid dose conversion factors; TID-14844 (1962), Table E-7 of Regulatory Guide 1.109, Rev. 1 (1977), or Supplement 1 to ICRP-30 (1980). TID-14844 thyroid dose conversion factors result in higher doses and lower allowable activity levels than the other two references and are, therefore, conservative.

Using thyroid dose conversion factors other than those given in TID-14844 results in lower doses and higher allowable activity but is justified by the discussion given in the Federal Register (FR page 23360 Vl 56 No 98 May 21, 1991). This discussion accompanied the final rulemaking on

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd)

10 CFR 20 by the NRC. In that discussion, the NRC stated that they were incorporating modifications to existing concepts and recommendations of the ICRP and NCRP into NRC regulations. Incorporation of the methodology of ICRP-30 into the part 20 revision was specifically mentioned with the changes being made resulting from changes in the scientific techniques and parameters used in calculating dose. In a response to a specific question as to whether or not the ICRP 30 dose parameters should be used, the NRC stated that "Appropriate parameters for calculating organ doses can be found in ICRP-30 and its supplements.....". Lastly, Commissioner Curtis provided additional views of the revised 10 CFR 20 with respect to the backfit rule. In that discussion, he stated that the AEC, when they issued the original part 20, had emphasized that the standards were subject to change with the development of new knowledge and experience. He went on to say that the limits given in the revised 10 CFR 20 were based on up-to-date metabolic models and dose factors. This Federal Register entry shows clearly that, in general, the NRC was updating 10 CFR 20 to incorporate ICRP-30 recommendations and data. Given this discussion, it is concluded that using ICRP thyroid dose conversion factors to calculate DOSE EQUIVALENT I-131 is acceptable. Also, the Reg Guide 1.109 thyroid dose conversion factors are higher than the ICRP-30 thyroid dose conversion factors for all five iodine isotopes in question. Therefore, using Reg Guide 1.109 thyroid dose conversion factors to calculate DOSE EQUIVALENT I-131 is more conservative than ICRP-30 and is therefore acceptable.

BASES

LCO 3.0.6 (continued)

However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' 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.

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the

(continued)

BASES

LCO 3.0.6 (continued)

ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross division inoperabilities. This explicit cross division verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABLE—OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system. C

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

(continued)

BASES

LCO 3.0.7 (continued)

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.

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.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. (B)

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 psig. 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 psig 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 limit of the specified Frequency, whichever is less, 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 have

(continued)

BASES

SR 3.0.3 (continued)

been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

SR 3.0.3 also provides a time limit for completion 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.

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.

(continued)

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.

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, on equipment that is inoperable, 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.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

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

(continued)

BASES

SR 3.0.4 (continued)

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 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.

SR 3.0.4 is only applicable when entering MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, or 3. The requirements of SR 3.0.4 do not apply in MODES 4 and 5, or 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.

BASES

LCO 3.0.6 (continued)

TSTF-273 (2) (3) INSERT 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.

(C)

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 ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of

(1) (2) (2)

(continued)

TSTF-273

INSERT LCO 3.0.6

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restrictions for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

3 division

2 OPERABLE-

C

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1235 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	24 months on a STAGGERED TEST BASIS
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction valve is unblocked.	24 months AND Once within 24 hours after piping temperature is restored to ≥ 70°F

ADMINISTRATIVE (continued)

A.5 CTS 4.1.5.d.3 footnote * requires the heat traced piping to be demonstrated unblocked whenever both heat tracing circuits have been found to be inoperable. The Frequency of CTS 4.1.5.d.3 footnote * has been changed such that the Surveillance is required if the piping temperature drops below the lower limit (70°F), similar to footnote * to CTS 4.1.5.b.2. Since the intent is to ensure no piping is blocked, and the temperature is the best indicator of a condition in which the piping can become blocked, this change is considered administrative in nature. 1C

A.6 CTS 4.1.5.d.3 requires a demonstration that the heat traced piping is unblocked by pumping from the storage tank to the test tank. Footnote * to this Surveillance states that it can be performed by any series of sequential, overlapping or total flow path steps such that the entire flow path is included. The allowance is unnecessary since the test can only be performed in one step; by pumping from the storage tank to the test tank. Therefore, this allowance has been deleted and its deletion is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of the method for performing CTS 4.1.5.d.1, the Surveillance to verify flow through the SLC subsystem into the reactor pressure vessel (initiating an explosive valve and the requirements on the replacement charges for explosive valve), are proposed to be relocated to the Bases. These details are not necessary to ensure that SLC System is maintained OPERABLE. The requirements of ITS 3.1.7 and SR 3.1.7.8 are adequate to ensure the capability to provide flow through each SLC subsystem into the reactor pressure vessel and to ensure SLC System OPERABILITY. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS .

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
<4.1.5.b.3> SR 3.1.7.6	Verify each SLC subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position, or can be aligned to the correct position.	31 days
<4.1.5.c> SR 3.1.7.7	Verify each pump develops a flow rate ≥ [41.2] gpm at a discharge pressure ≥ [1300] psig.	In accordance with the Inservice Testing Program or 92 days
<4.1.5.d.1> SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	[18] months on a STAGGERED TEST BASIS
<4.1.5.d.3> SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction is unblocked.	[18] months AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-1

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.1.7 - STANDBY LIQUID CONTROL SYSTEM

1. The bracketed requirement has been deleted since it is not applicable to NMP2. The following requirements have been revised and/or renumbered, where applicable, to reflect this deletion.

2. The brackets have been removed and the proper plant specific information/value has been provided.

3. The NMP2 design is such that heat tracing is only applied up to the pump suction valve of each SLC pump. Therefore, the SR has been changed to reflect this design.

4. The proper NMP2 nomenclature has been used. This is also consistent with the nomenclature used in SR 3.1.7.1 and SR 3.1.7.2.

5. The second Frequency for ISTS SR 3.1.7.9 (ITS SR 3.1.7.9) is being changed from being based on solution temperature to piping temperature. The SR requires a verification that all heat traced piping is unblocked. A change in solution temperature in the tank does not necessarily have an impact on the piping temperature, as long as the piping heat trace circuit is functioning properly. The intent of the second Frequency is to ensure that, if the heat tracing is inoperable such that piping temperature falls below 70°F, after the heat tracing is restored to OPERABLE status and the piping temperature is ≥70°F the piping is still unblocked. This is supported by the ISTS Bases description for this second Frequency, which describes the requirement as required to be performed after "piping" temperature is restored. C

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Reactor Vessel Steam Dome Pressure – High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.16	≤ 1072 psig
4. Reactor Vessel Water Level – Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.16	≥ 157.8 inches
5. Main Steam Isolation Valve – Closure	1	8	F	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.16	≤ 12% closed
6. Drywell Pressure – High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 1.88 psig
7. Scram Discharge Volume Water Level – High					
a. Transmitter/Trip Unit	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.14	≤ 49.5 inches
	5(a)	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.14	≤ 49.5 inches
b. Float Switch	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 49.5 inches
	5(a)	2	H	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 49.5 inches
8. Turbine Stop Valve – Closure	≥ 30% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.16	≤ 7% closed

(continued)

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

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.2	----------NOTE---------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. ---------- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.3	Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.2.1.4	----------NOTE---------- Neutron detectors are excluded. ---------- Verify the RBM is not bypassed when THERMAL POWER is ≥ 30% RTP and a peripheral control rod is not selected.	24 months
SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ 10% RTP.	24 months
SR 3.3.2.1.6	----------NOTE---------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. ---------- Perform CHANNEL FUNCTIONAL TEST.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.2.3	Calibrate the analog trip modules.	92 days
SR 3.3.4.2.4	Verify, for the Reactor Vessel Steam Dome Pressure—High Function, the low frequency motor generator trip is not bypassed for > 29 seconds when THERMAL POWER is > 5% RTP.	24 months
SR 3.3.4.2.5	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level—Low Low, Level 2: ≥ 101.8 inches; and b. Reactor Vessel Steam Dome Pressure—High: ≤ 1080 psig.	24 months
SR 3.3.4.2.6	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	24 months

Table 3.3.6.1-1 (page 3 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
3. RCIC System Isolation (continued)						
g. RHR Equipment Room Area Temperature – High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 144.5°F	
h. Reactor Building Pipe Chase Area Temperature – High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6		
El. = 319 ft.					≤ 144.5°F	
El. = 292 ft.					≤ 140.5°F	
El. = 266 ft.					≤ 140.5°F	
El. = 206 ft.					≤ 140.5°F	
i. Reactor Building General Area Temperature – High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 134°F	
j. Area Temperature – Timer	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.15 seconds	C
k. RCIC/RHR Steam Flow – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 40.73 inches water	C
l. RCIC/RHR Steam Flow – Timer	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 13 seconds	C
m. Manual Initiation	1,2,3	1[c]	G	SR 3.3.6.1.6	NA	C
4. Reactor Water Cleanup (RWCU) System Isolation						
a. Differential Flow – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 165.5 gpm	
b. Differential Flow – Timer	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3,6.1.5 SR 3.3.6.1.6	≤ 47 seconds	

(continued)

(c) Only inputs into one of the two trip systems.

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

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
1. Divisions 1 and 2 – 4.16 kV Emergency Bus Undervoltage				
a. Loss of Voltage – 4.16 kV Basis	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 2950 V and ≤ 3468 V	
b. Loss of Voltage – Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 2.80 seconds and ≤ 3.20 seconds	1 E
c. Degraded Voltage – 4.16 kV Basis	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 3820 V and ≤ 3898 V	
d. Degraded Voltage – Time Delay, No LOCA	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 27.8 seconds and ≤ 32.2 seconds	1 E
e. Degraded Voltage – Time Delay, LOCA	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 7.4 seconds and ≤ 8.6 seconds	1 E
2. Division 3 – 4.16 kV Emergency Bus Undervoltage				
a. Loss of Voltage – 4.16 kV Basis	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 2950 V and ≤ 3468 V	
b. Loss of Voltage – Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 2.8 seconds and ≤ 3.2 seconds	1 E
c. Degraded Voltage – 4.16 kV Basis	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 3820 V and ≤ 3898 V	
d. Degraded Voltage – Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 11.0 seconds and ≤ 13.0 seconds	1 E

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When an RPS electric power monitoring assembly is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the other RPS electric power monitoring assembly for the associated RPS logic bus maintains trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.8.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage (with time delay set to ≤ 4 seconds) Bus A ≤ 133.8 V Bus B ≤ 133.8 V b. Undervoltage (with time delay set to ≤ 4 seconds) Bus A ≥ 115.5 V Bus B ≥ 114.2 V c. Underfrequency (with time delay set to ≤ 4 seconds) Bus A ≥ 57.5 Hz Bus B ≥ 57.5 Hz	24 months
SR 3.3.8.2.3	Perform a system functional test.	24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When an RPS electric power monitoring assembly is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the other RPS electric power monitoring assembly for the associated RPS scram solenoid bus maintains trip capability.

SURVEILLANCE	FREQUENCY
SR 3.3.8.3.1 Perform CHANNEL FUNCTIONAL TEST.	184 days

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1 and SR 3.3.2.1.2 (continued)

allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. Operating experience has shown that these components usually pass the Surveillance when performed at the 92 day Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the entire 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 184 days is based on the analysis in Reference 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 when ≥ 30% RTP, 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 to enable the RBM. If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.3 and SR 3.3.1.1.7. The 24 month Frequency is based on the analysis in Reference 8. 1

(continued)

BASES

BACKGROUND (continued)

are not downscale (approximately ≤ 4% RTP), the LFMG breakers for both recirculation pumps will be tripped. In addition, the required APRM input to each Reactor Vessel Steam Dome Pressure—High channel must be from separate APRMs.

There are two fast speed motor breakers and two LFMG breakers provided for each of the two recirculation pumps for a total of eight breakers. The output of each trip system will trip one fast speed breaker and both LFMG breakers (the input and output breakers) for each recirculation pump. However, for the LFMG breaker trip portion of each trip system, only one LFMG breaker (either input or output) per recirculation pump is required to be tripped for ATWS-RPT System OPERABILITY, with each trip system required to trip a different LFMG breaker. Furthermore, the combination of trip system inputs for one LFMG set may be different for the other LFMG set.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ATWS-RPT is not assumed to mitigate any accident or transient 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.

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 3.3.4.2.5. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump fast speed breakers and the LFMG input and output breakers. C

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

(continued)

BASES

ACTIONS (continued)

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 breaker(s) 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 recirculation pump breaker(s) from service in an orderly manner and without challenging plant systems. 1C

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. 4) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.3 (continued)

conservative than the Allowable Value specified in SR 3.3.4.2.5. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the ATWS analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.4.2.4

This SR ensures that the LFMG breaker trip portion of the ATWS-RPT initiated from the Reactor Vessel Steam Dome Pressure—High Function will not be inadvertently bypassed for > 29 seconds when THERMAL POWER is > 5% RTP. This involves verification of the time delay and calibration of the APRM Downscale trip channel. Adequate margins for the instrument setpoint methodologies are incorporated into the actual APRM setpoint. If any time delay or APRM Downscale setpoint is nonconservative (i.e., the Reactor Vessel Steam Dome Pressure—High Function is bypassed for > 29 seconds when THERMAL POWER is > 5% RTP), the affected Reactor Vessel Steam Dome Pressure—High Function is considered inoperable. Alternately, if only the APRM Downscale setpoint is nonconservative, the APRM channel can be placed in the conservative condition (e.g., placed in the inop trip condition). If placed in the conservative condition, this SR is met and the associated Reactor Vessel Steam Dome Pressure—High Function is considered OPERABLE.

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the APRM setpoint analysis and is also based upon engineering judgement and the reliability of the time delay components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.5 1C

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 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis and engineering judgment.

SR 3.3.4.2.6 1C

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.

REFERENCES

1. USAR, Section 7.6.1.8.

2. 10 CFR 50.36(c)(2)(ii).

3. USAR, Section 15.8.

4. 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.

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 (AOOs) 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 transmitters and drywell pressure is monitored by two redundant pressure transmitters, each providing input to a trip unit. The outputs of the four trip units (two trip units 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 10 seconds if offsite power is available; otherwise the pump is started in approximately 6 seconds after AC power from the DG is available.

The LPCS full flow test line isolation valve, is closed on a LPCS initiation signal to allow full system flow assumed in the accident analysis.

(continued)

BASES

BACKGROUND

Low Pressure Core Spray System (continued)

The LPCS pump discharge flow is monitored by a differential pressure transmitter. 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 differential pressure between the low pressure side of the LPCS injection valve and 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 differential pressure transmitter, which is, in turn, connected to a trip unit. The output of the trip unit is connected to a relay 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 transmitters per division and drywell pressure is monitored by two redundant pressure transmitters per division, each providing input to a trip unit. The outputs of the four Division 2 LPCI (loops B and C) trip units (two trip units 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 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.

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

Upon receipt of an initiation signal, the LPCI Pump C is automatically started in approximately 10 seconds if offsite power is available; otherwise the pump is started in approximately 6 seconds after AC power from the DG is available while LPCI pumps A and B are automatically started in approximately 5 seconds if offsite power is available; otherwise the pumps are started in approximately 1 second after AC power from the DG is available. These time delays limit the loading on the normal and standby power sources.

Each LPCI subsystems discharge flow is monitored by a differential pressure transmitter. 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 spray isolation valves (which are also PCIVs) and suppression pool cooling full flow test valves are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and, in the case of the spray isolation valves, to maintain the containment isolated in the event LPCI is not operating.

The RHR A and B heat exchanger sample and RHR B discharge to radwaste valves (Group 4 valves) are closed on either a Reactor Vessel Water Level—Low, Level 3 signal or a Drywell Pressure—High signal to allow full system flow assumed in the accident analysis. (The RHR A discharge to radwaste valves are manual valves; they do not receive an automatic signal.) These valves can also be closed using the remote manual control switches. Reactor vessel water level is monitored by two differential pressure transmitters per division and drywell pressure is monitored by two pressure transmitters per division, each providing input to a trip unit. The outputs of these channels for each Function are arranged into a two-out-of-two trip system for each division. The LPCI A (Division 1) trip systems close the outboard valves while the LPCI B (Division 2) trip systems close the inboard valves. However, since only one of the valves in each line must be closed to preclude flow diversion, and the valves must be capable of closing when

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

the associated LPCI receives an initiation signal, only the valves receiving power and logic from their associated division must be capable of closing. Thus, the LPCI A trip systems must close the outboard RHR A heat exchanger sample valve and LPCI B trip systems must close the inboard RHR B heat exchanger sample valve and the inboard RHR B discharge to radwaste valve.

The LPCI subsystems monitor the differential pressure between the low pressure side of the LPCI injection valves and 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 one transmitter per valve, each providing input to a trip unit. The output of each trip unit is connected to a relay whose contact is 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 transmitters and drywell pressure is monitored by four redundant pressure transmitters, each providing input to a trip unit. The outputs of the trip units 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 and pressure are monitored by a differential pressure and pressure transmitter, respectively. Each transmitter is connected to a trip unit. When the pump is running (as indicated by the pressure transmitter) 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.

(continued)

BASES

BACKGROUND

High Pressure Core Spray System (continued)

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

The HPCS System also monitors the HPCS pump suction pressure, which provides an indication of the water level in condensate storage tank B (CST), and the suppression pool water level, 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 pump suction pressure (indicating low water level in the CST) falls below a preselected level for a preselected time, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. Two pressure transmitters are used to detect low pump suction pressure and a single time delay relay is used to provide a short delay in the automatic suction swap feature. Either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close (one-out-of-two logic). Once low pump suction pressure is detected, a time delay relay times out, then the automatic suction swap occurs. 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 differential pressure transmitters are also used to detect high suppression pool water level, with a one-out-of-two logic similar to the pump suction pressure 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 one-out-of-two taken twice to provide high

(continued)

BASES

BACKGROUND

High Pressure Core Spray System (continued)

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 transmitters for Reactor Vessel Water Level—Low Low Low, Level 1 and one differential pressure transmitter for confirmed Reactor Vessel Water Level—Low, Level 3 in each of the two ADS trip systems. Each of these transmitters connects to a trip unit, 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 transmitters from each of the two low pressure ECCS pumps in the associated Division (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.

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BASES

BACKGROUND

Automatic Depressurization System (continued)

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 (one string only); 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 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 the use of two manual switch 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).

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 the Division 1 and 2 DGs, and Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High for the Division 3 DG. 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 transmitters and drywell pressure is

(continued)

BASES

BACKGROUND

Diesel Generators (continued)

monitored by two redundant pressure transmitters per DG, each providing input to a trip unit. The outputs of the four divisionalized trip units (two trip units 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., Division 1 DG receives an initiation signal from Division 1 ECCS (LPCS and LPCI A); Division 2 DG receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C); and Division 3 DG 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 10 seconds, and will run in standby conditions (rated voltage and speed, with the DG output breaker open). The DGs will only energize their respective emergency buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2, and 3. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS instrumentation satisfies Criterion 3 of 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 upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Table 3.3.5.1-1, footnote (b), is added to show that certain ECCS instrumentation Functions are also required to be OPERABLE to perform DG initiation.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

Some Functions (i.e., Functions 1.k, 1.l, 2.j, and 3.g) have both an upper and lower analytic limit that must be evaluated. The Allowable Values and 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 Systems

1.a, 1.b, 2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and 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 and certain RHR valves are closed at Level 3 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 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 (Ref. 2). However, while no credit is taken in these analyses to start the DGs, they are retained for overall redundancy and diversity as required by the NRC in the plant licensing basis. The Reactor Vessel Water Level—Low, Level 3 is implicitly assumed to allow full system flow assumed in References 1 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.

Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low Low, Level 1 signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low, Level 3

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 1.b, 2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

(LCO 3.3.1.1, "RPS Instrumentation,") since the sensors are common to the RPS instrumentation. 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, Level 3 Function per associated Division are only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE, to ensure that no single instrumentation failure can preclude ECCS initiation. 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 is required to be OPERABLE, to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and the Division 1 DG while the other two channels input to LPCI B, LPCI C, and the Division 2 DG.) Refer to LCO 3.5.1 and LCO 3.5.2, "ECCS—Shutdown," for Applicability Bases for the low pressure ECCS subsystems.

1.c, 1.d, 2.c, 2.d. Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation)

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 and certain RHR valves are closed upon receipt of the Drywell Pressure—High (Boundary Isolation) Function in order to minimize the possibility of fuel damage. Although, no credit is taken for the Drywell Pressure—High Function to start the low pressure ECCS in any design basis accident or transient analysis (thus Drywell Pressure—High (Boundary Isolation) Function is also not assumed), they are retained for overall redundancy and diversity as required by the NRC in the plant licensing basis. In addition, credit is taken for the Drywell Pressure—High Function to start the associated DGs (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 2.c, 2.d. Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation) (continued)

High drywell pressure signals are initiated from pressure transmitters that sense drywell pressure. The Drywell Pressure—High Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment. The Drywell Pressure—High (Boundary Isolation) Allowable Value was chosen to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1) since the sensors are common to the RPS instrumentation.

The Drywell Pressure—High Function is required to be OPERABLE when the associated ECCS is 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 the Division 1 DG while the other two channels input to LPCI B, LPCI C, and the Division 2 DG.) The Drywell Pressure—High (Boundary Isolation) is required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the Drywell Pressure—High (Boundary Isolation) 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 and Drywell Pressure—High (Boundary Isolation) Functions are not required since there is insufficient energy in the reactor to pressurize the primary containment to the Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation) Functions setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

1.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, 2.h. LPCS and LPCI Pump Start—Time Delay Relays (Normal and Emergency Power)

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 Time Delay Relay (Normal Power) Function is necessary when power is being supplied from offsite power,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, 2.h. LPCS and LPCI Pump Start—Time Delay Relays (Normal and Emergency Power) (continued)

and the Time Delay Relay (Emergency Power) Function is necessary when power is being supplied from the standby power sources (DG). The Pump Start—Time Delay Relays (Normal and Emergency Power) 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.

There are four Pump Start—Time Delay Relays (Normal Power) and four Pump Start—Time Delay Relays (Emergency Power), one of each type in each of the low pressure ECCS pump start logic circuits. While each time delay relay is dedicated to a single pump start logic, a single failure of a Pump Start—Time Delay Relay (Normal or Emergency Power) could result in the failure of the two low pressure ECCS pumps, powered from the same emergency bus, to perform their intended function within the assumed ECCS RESPONSE TIMES (e.g., as in the case where both ECCS pumps on one emergency bus start simultaneously due to an inoperable time delay relay). This still leaves two of the four low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Values for the Pump Start—Time Delay Relays (Normal and Emergency Power) are chosen to be short enough so that ECCS operation is not degraded.

Each channel of Pump Start—Time Delay Relay (Normal and Emergency Power) Function is only required to be OPERABLE when the associated low pressure ECCS subsystem 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.

1.i, 1.j, 2.i. LPCS and LPCI Differential Pressure—Low (Injection Permissive)

Low differential pressure across the injection valves 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 Differential

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.i, 1.j, 2.i. LPCS and LPCI Differential Pressure—Low (Injection Permissive) (continued)

Pressure—Low (Injection Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition, the Differential Pressure—Low (Injection Permissive) Function is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Differential Pressure—Low (Injection Permissive) signals are initiated from four differential pressure transmitters that sense the pressure difference across the injection valves of the low pressure ECCS subsystems.

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 Differential Pressure—Low (Injection Permissive) 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.k, 1.l, 2.j. LPCS and LPCI Pump Discharge Flow—Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not 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 (Bypass) 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

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.k, 1.l, 2.j. LPCS and LPCI Pump Discharge Flow—Low (Bypass) (continued)

function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One differential pressure transmitter per ECCS pump is used to detect the associated subsystems flow rate. The logic is arranged such that each transmitter 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 approximately 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 (Bypass) 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 (Bypass) 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.m, 2.k. 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).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.m, 2.k. Manual Initiation (continued)

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. 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.

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 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 (Ref. 2). However, no credit is taken in this analysis to start the HPCS DG. 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 transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel 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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level—Low Low Low, Level 1.

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. Although no credit is taken for the Drywell Pressure—High Function to start the HPCS System in any DBA or transient analyses, credit is taken for this Function to start the associated DG; that is, HPCS is assumed to be initiated on Reactor Water Level—Low Low, Level 2 while the associated DG is assumed to be initiated on Drywell Pressure—High. 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 transmitters 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 setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

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BASES

APPLICABLE SAFETY ANALYSES, 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 credited 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 four differential pressure transmitters from the wide 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.

Four 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, 3.e. Pump Suction Pressure—Low and Pump Suction Pressure—Timer

Low pump suction pressure, which is an indication of 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 pump suction pressure (indicating low water level in the CST) falls below a preselected level for a preselected time, 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 Functions are

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d, 3.e. Pump Suction Pressure—Low and Pump Suction Pressure—Timer (continued)

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.

Pump Suction Pressure—Low signals are initiated from two pressure transmitters. The Pump Suction Pressure—Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST. The pressure at which the transfer occurs also ensures sufficient volume of water is used by the HPCS pump before the transfer occurs and is analytically determined to prevent the effects of vortexing. The Pump Suction Pressure—Timer Function is initiated by a single time delay relay. While the Pump Suction Pressure—Timer Function is provided to prevent spurious suction source automatic swaps, the Allowable Value is low enough such that the automatic suction swap from the CST to the suppression pool will occur before adequate pump suction head is lost.

Two channels of the Pump Suction Pressure—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. In addition, one channel of the Pump Suction Pressure—Timer Function is only required to be OPERABLE when HPCS is required to be OPERABLE. Thus, the Functions are required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the Functions are 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.f. 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 S/RVs. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.f. Suppression Pool Water Level—High (continued)

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.

Suppression Pool Water Level—High signals are initiated from two differential pressure transmitters. 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.g, 3.h. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass)

The minimum flow instruments are 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 and high pump discharge pressure are sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump or the discharge pressure is low (indicating the HPCS pump is not operating). The HPCS System Flow Rate—Low (Bypass) and HPCS Pump Discharge Pressure—High (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.g, 3.h. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass) (continued)

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 differential pressure transmitter is used to detect the HPCS System's flow rate. The logic is arranged such that the transmitter causes the minimum flow valve to open, provided the HPCS pump discharge pressure, sensed by another transmitter, is high enough (indicating the pump is operating). The logic will close the minimum flow valve once the closure setpoint is exceeded. (The valve will also close upon HPCS pump discharge pressure decreasing below the setpoint.)

The HPCS System Flow Rate—Low (Bypass) Allowable Values are 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. The HPCS Pump Discharge Pressure—High (Bypass) Allowable Value is set high enough to ensure that the valve will not be open when the pump is not operating.

One channel of each 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.i. Manual Initiation

The Manual Initiation switch and push button channel introduces 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 USAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

(continued)

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APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

3.i. Manual Initiation (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 button. Two channels of the Manual Initiation Function are only required to be OPERABLE when the HPCS System is 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 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 Reference 2. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low Low Low, Level 1 signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen high enough to allow time for the low pressure core spray and injection 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.

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BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

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 timer, or to inhibit initiation permanently. The ADS Initiation Timer Function is assumed to be OPERABLE for the accident analyses of Reference 2 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.

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.

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

The Reactor Vessel Water Level—Low, Level 3 (Permissive) 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 (Permissive) signals are initiated from two differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

vessel. The Allowable Value for Reactor Vessel Water Level—Low, Level 3 (Permissive) 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.

Two channels of Reactor Vessel Water Level—Low, Level 3 (Permissive) 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 from the LPCS and LPCI pumps (indicating that the associated pump is running) 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 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 transmitters, 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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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.

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. Manual Initiation

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 USAR. However, the Function is retained for overall redundancy and diversity of the ADS 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 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

(continued)

BASES

ACTIONS (continued)

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.

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, B.3.1, and B.3.2

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same 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, 1.c, 1.d, 2.a, 2.b, 2.c, and 2.d (i.e., low pressure ECCS and associated DGs). The Required Action B.2 features would be the HPCS System and associated DG. For Required Action B.1, redundant automatic initiation capability is lost if: (a) one or more Function 1.a channels and one or more Function 2.a channels are inoperable and untripped, and the associated flow path(s) unisolated; (b) one or more Function 1.b channels and one or more Function 2.b channels are inoperable and untripped; (c) one or more Function 1.c channels and one or more Function 2.c channels are inoperable and untripped; or (d) one or more Function 1.d channels and one or more Function 2.d channels are inoperable and untripped, and the associated flow path(s) unisolated. 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.

(continued)

BASES

ACTIONS

B.1, B.2, B.3.1, and B.3.2 (continued)

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 (i.e., loss of automatic start capability for Functions 3.a and 3.b) 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 12 hour or 24 hour allowance of Required Action B.3.1 is not appropriate and the feature(s) associated with the inoperable, untripped channels (and associated flow path(s) unisolated, as appropriate) must be declared inoperable within 1 hour. As noted (Note 1 to Required Action B.1 and 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 12 hours or 24 hours (as allowed by Required Action B.3.1) 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

(continued)

BASES

ACTIONS

B.1, B.2, B.3.1, and B.3.2 (continued)

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 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. 5 and 6) 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.3.1. 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 initiation), Condition H must be entered and its Required Action taken. An alternate Required Action is provided (Required Action B.3.2) for Functions 1.a, 1.d, 2.a, and 2.d. For these Functions, in lieu of tripping the channel or entering Condition H (and taking its Required Actions), the affected RHR flow path(s) can be isolated. Isolating the affected flow path(s) accomplishes the safety function of the inoperable channel and does not render the associated LPCI subsystem inoperable. Therefore, this action is acceptable. The allowed Completion Time for isolating the affected flow path(s) is the same as the Completion Time allowed for these Functions in Required Action B.3.1.

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.e, 1.f, 1.g, 1.h, 1.i, 1.j, 2.e, 2.f, 2.g, 2.h,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

and 2.i (i.e., low pressure ECCS). For Functions 1.e, 1.f, 2.e, and 2.f, redundant automatic initiation capability is lost if the Function 1.e or 1.f channel concurrent with Function 2.e or 2.f channel are inoperable. For Functions 1.g, 1.h, 2.g, and 2.h, redundant automatic initiation capability is lost if the Function 1.g or 1.h channel concurrent with Function 2.g or 2.h channel are inoperable. For Functions 1.i, 1.j, and 2.i, redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.i, 1.j, and 2.i are inoperable. In addition, a Pump Start —Time Delay Relay may be inoperable in such a fashion that the associated offsite circuit or DG is affected (e.g., as in the case where two loads start outside the proper load block interval). If this is the case, the associated ACTIONS of LCO 3.8.1 or LCO 3.8.2, as appropriate, need to be taken. 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.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, and 2.h, the affected portion of the Divisions are LPCS, LPCI A, LPCI B, and LPCI C. For Functions 1.i, 1.j, and 2.i, the affected portions of the Division are only those low pressure ECCS pumps directly affected by the inoperable channel (i.e., whose injection valve will not actuate properly due to an inoperable channel).

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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Note 2 states that Required Action C.1 is only applicable for Functions 1.e, 1.f, 1.g, 1.h, 1.i, 1.j, 2.e, 2.f, 2.g, 2.h, and 2.i. The Required Action is not applicable to Functions 1.m, 2.k, and 3.i (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 the Function 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 (i.e., 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.

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.

(continued)

BASES

ACTIONS (continued)

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 HPCS initiation capability is lost if two Function 3.d channels or two Function 3.f channels are inoperable and untripped or if the one Function 3.e channel is 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.

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

(continued)

BASES

ACTIONS

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

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 (Bypass) Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.k, 1.l, and 2.j (i.e., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.k, 1.l, and 2.j 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.

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 Functions 3.g and 3.h since the loss of one channel results

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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 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.

(continued)

BASES

ACTIONS (continued)

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

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action 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 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

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

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 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.f and 5.e (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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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 HCPS 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 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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours as follows: (a) for Functions 3.e, 3.g, 3.h, and 3.i; and (b) for Functions other than 3.e, 3.g, 3.h, and 3.i 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 reliability analyses (Refs. 5 and 6) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ECCS will initiate when necessary.

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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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 References 5 and 6.

SR 3.3.5.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be not within its required Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 5 and 6.

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 Frequency of SR 3.3.5.1.4 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.5.1.5 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 3.3.5.1.6

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 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. USAR, Section 5.2.
2. USAR, Section 6.3.
3. USAR, 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.
6. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

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 transmitters that are connected to four trip units. The outputs of the trip units are connected to relays whose 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 to the reactor vessel.

The RCIC System also monitors the RCIC pump suction pressure, which provides an indication of the water level in the condensate storage tank A (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 pump suction pressure (water level in the CST) falls below a preselected pressure for a preselected time, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. Two pressure transmitters are used to

(continued)

BASES

BACKGROUND (continued)

detect low pump suction pressure (water level in the CST) and a single time delay relay is used to provide a short delay in the automatic suction swap feature. Either transmitter along with its associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close (one-out-of-two logic). Once low pump suction pressure is detected, a time delay relay times out, then the automatic suction swap occurs. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (one-out-of-two taken twice 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 unit) 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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 transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel 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.

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; but this is not required for OPERABILITY of the Level 8 instrumentation.)

Reactor Vessel Water Level—High, Level 8 signals for RCIC are initiated from four differential pressure transmitters from the wide 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

2. Reactor Vessel Water Level—High, Level 8 (continued)

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.

Four 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. 4. Pump Suction Pressure—Low and Pump Suction Pressure—Timer

Low pump suction pressure, which is an indication of 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 the pump suction pressure (water level in the CST) falls below a preselected pressure for a preselected time, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. This ensures that an adequate supply at makeup water is available to the RCIC pump. The pressure at which the transfer occurs ensures sufficient volume of water is used by the RCIC pump before the transfer occurs and is analytically determined to prevent the effects of vortexing. 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 pressure transmitters are used to detect low pump suction pressure (water level in the CST). The Pump Suction Pressure—Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CST. The Pump Suction Pressure—Timer Function is initiated by a single time delay relay. While the Pump Suction Pressure—Timer Function is provided to prevent spurious suction source automatic swaps, the Allowable Value

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. 4. Pump Suction Pressure—Low and Pump Suction Pressure—Timer (continued)

is low enough such that the automatic suction swap from the CST to the suppression pool will occur before adequate pump suction head is lost.

Two channels of Pump Suction Pressure—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. In addition, one channel of the Pump Suction Pressure—Timer is required to be OPERABLE when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for RCIC Applicability Bases.

5. 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 USAR. 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.

ACTIONS

A Note has been provided (Note 1) 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.

(continued)

BASES

ACTIONS (continued)

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 second Note has been added (Note 2) that allows the Function 2 channels to be inoperable solely for performance of SR 3.5.3.4 without requiring entry into the associated Conditions and Required Actions. The Reactor Vessel Water Level—High, Level 8 Function uses the wide range water level instruments, which are calibrated under hot conditions. However, SR 3.5.3.4 (the RCIC System flow test performed at low reactor pressure) is performed under conditions that result in the wide range water level instruments reading higher than actual reactor vessel water level (which is controlled using the narrow range water level instruments). The readings can be such that the level 8 trip is received. Therefore, this Note allows bypassing all the channels of the Reactor Vessel Water Level—High, Level 8 Function to perform SR 3.5.3.4. This is acceptable since the duration of the Surveillance test is short and the RCIC System is being controlled by an operator who can secure the RCIC System if an actual high water level condition (as indicated by the narrow range instruments) is detected.

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.

(continued)

BASES

ACTIONS (continued)

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 (i.e., loss of automatic low water level start capability for Function 1 and loss of automatic high water level trip capability for Function 2). In this case, automatic initiation capability is lost if two channels of a Function, 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." 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 or two inoperable, untripped Reactor Vessel Water Level—High, Level 8 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.

(continued)

BASES

ACTIONS (continued)

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 manual RCIC initiation capability exists, is not required. This is allowed since this Function is not assumed in any accident or transient analysis, thus 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 initiation capability being lost for the RCIC System. In this case, automatic initiation capability is lost if two Function 3 channels are inoperable and untripped or if the one Function 4 channel is 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.

(continued)

BASES

ACTIONS

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

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 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 4 and 5; and (b) for up to 6 hours for Functions 1, 2, and 3 provided the associated Function maintains RCIC 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

SR 3.3.5.2.1

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 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 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

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.5.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be re-adjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.5.2.4

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 a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.5

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

The 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.5 (continued)

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.

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 units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) ambient and differential temperatures and time delay relays, (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) and RCIC/residual heat removal (RHR) steam line flow and time delay relays, (h) Standby Gas Treatment (SGT) System exhaust radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential flow and time delay relays, (l) reactor vessel pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. The only exception is the SGT System exhaust radiation sensor. In addition, manual isolation of the logics is provided. 1C

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

(continued)

BASES

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 trip system is associated with the outboard valves.

The exceptions to this arrangement are the Main Steam Line Flow—High, Main Steam Line Tunnel Lead Enclosure Temperature—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 trip systems (effectively, two one-out-of-four taken twice logic), with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Main Steam Line Tunnel Lead Enclosure Temperature—High Function uses 12 temperature channels, three for each trip string. One sensor in each trip string is measuring the temperature in one of the three areas of the lead enclosure. Two trip strings make up each trip system, and both trip systems must trip to cause a MSL isolation. One sensor is required to trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two logic. Therefore, this is effectively a one-out-of-two taken twice logic arrangement for each enclosure area to initiate isolation of the MSIVs. The 12 temperature channels are connected into two two-out-of-two trip systems for each enclosure area, 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 switch and push button. The four channels from two

(continued)

BASES

BACKGROUND

1. Main Steam Line Isolation (continued)

switch and push buttons input into one trip system and the four channels from the switch and push buttonsother 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 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 two-out-of-two trip systems. The two exceptions to this logic arrangement are the SGT System Exhaust Radiation—High and the Manual Initiation Functions. The SGT System Exhaust Radiation—High Function uses two channels, with one channel in each trip system arranged in a one-out-of-one logic. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. In general, one trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system closes one of the two valves on each penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement, which have been previously approved by the NRC as part of the issuance of the Operating License, are described in USAR Table 6.2-56 (Ref. 1). In addition, the withdrawal of the traversing in-core probes using the drive mechanisms is part of the Group 3 isolation valve function.

(continued)

BASES

BACKGROUND

2. Primary Containment Isolation (continued)

Reactor Vessel Water Level—Low, Low, Level 2 Function isolates the Group 2, 3, 8, and 9 valves. Drywell Pressure—High isolates the Group 3, 8, and 9 valves. SGT System Exhaust Radiation—High Function isolates the Group 9 valves.

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. Functions 3.g, 3.h, and 3.i (RHR Equipment Room Area Temperature—High, Reactor Building Pipe Chase Area Temperature—High, and Reactor Building General Area Temperature—High Functions) have one channel in each trip system in each room/area for a total of four, eight, and ten channels per Function, respectively; but the logic is the same (one-out-of-one per room/area). 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. Two 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 channels and four turbine exhaust diaphragm pressure channels, respectively. The outputs from these channels are connected into two 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 System Isolation Functions isolate the Group 10 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.d and 4.e (Pump Room Area Temperature—High and Reactor Building Pipe Chase Area Temperature—High) have one channel in each trip system in each room/area for a total of four and eight channels per Function, respectively, but the logic is the same (one-out-of-one per room/area). Each of

(continued)

BASES

BACKGROUND

4. Reactor Water Cleanup System Isolation (continued)

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 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 two-out-of-two trip systems, each trip system isolating one of the two RWCU valves. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. Each trip system isolates one of the two RWCU valves.

RWCU System Isolation Functions isolate the Group 6 and 7 valves.

5. RHR Shutdown Cooling (SDC) System Isolation

The RHR Shutdown Cooling System Isolation receives input signals from six Functions. The Reactor Vessel Water Level—Low and Reactor Vessel Pressure—High Functions each have four channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. The reactor vessel pressure is arranged into two one-out-of-two trip systems. RHR Equipment Room Area Temperature—High, Reactor Building Pipe Chase Area Temperature—High, and Reactor Building General Area Temperature—High Functions each have one channel in each trip system in each area (one-out-of-one logic for each area) for a total of four, eight, and ten channels per Function, respectively. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. Each of the two trip systems is connected to one of the two valves on the shutdown cooling suction line penetration so that

(continued)

BASES

BACKGROUND

5. RHR Shutdown Cooling (SDC) System Isolation (continued)

operation of either trip system isolates the penetration. In addition, each of the two trip systems is connected to the shutdown cooling return line valves of one RHR SDC subsystem, and one trip system is connected to the RHR reactor head spray outboard isolation valve.

The RHR Shutdown Cooling System Isolation Functions isolate the Group 5 valves.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 2 and 3 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 4. 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

(continued)

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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

Certain Emergency Core Cooling Systems (ECCS) valves (e.g., RHR suppression pool spray isolation valves) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS. Some instrumentation and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "ECCS 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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Low, Level 1 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Low, Level 1 Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 2). The isolation of the MSL on Level 1 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 transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Level 1 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 100 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. 5). 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Function closes the MSIVs prior to pressure decreasing below 766 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 pressure transmitters that are connected to the MSL header. The transmitters are arranged such that, even though physically separated from each other, each transmitter is able to detect low MSL pressure. Four channels of Main Steam Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 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 steam line break (MSLB) accident (Ref. 6). 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 100 limits.

The MSL flow signals are initiated from 16 differential pressure transmitters that are connected to the four MSLs (the differential pressure transmitters sense differential pressure across a flow venturi). The transmitters are arranged such that, even though physically separated from

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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.

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. 7). Since the integrity of the condenser is an assumption in offsite dose calculations (Ref. 8), 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 pressure transmitters that sense the pressure 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 stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

This Function isolates the Group 1 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.e, 1.f. Main Steam Line 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 USAR, 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.

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 Line 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 temperature and differential temperature monitoring Allowable Values are chosen to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 1 valves.

1.g. Main Steam Line Tunnel Lead Enclosure Temperature—High

Main Steam Line Tunnel Lead Enclosure Temperature—High is provided to detect a leak in a main steam line in the main steam line tunnel lead enclosure and also provides diversity to the high flow instrumentation. This enclosure is divided in three areas (west, center, and east). The isolation

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.g. Main Steam Line Tunnel Lead Enclosure Temperature—High (continued)

occurs when a very small leak has occurred in any one of the three areas of the enclosure. 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 USAR, since bounding analyses are performed for large breaks such as MSL breaks.

Main Steam Line Tunnel Lead Enclosure Temperature—High signals are initiated from thermocouples located in the area being monitored. Twelve channels of Main Steam Line Tunnel Lead Enclosure Temperature—High Function are available and are required to be OPERABLE (four in each of the three areas) to ensure that no single instrument failure can preclude the isolation function.

The Main Steam Line Tunnel Lead Enclosure Temperature—High Allowable Value is chosen to detect a leak equivalent to 25 gpm. In addition, as ambient temperature in the main steam line tunnel lead enclosure increases, the Allowable Value is allowed to be increased as described in footnote (b) to Table 3.3.6.1-1. This is permitted provided the main steam line tunnel lead enclosure is visually inspected to ensure the ambient temperature increase is not due to a steam leak.

This Function isolates the Group 1 valves.

1.h. 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 USAR 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 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.h Manual Initiation (continued)

Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the MSL 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. 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 2 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 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 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.

This Function isolates the Group 2, 3, 8, and 9 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.b. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the drywell. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure—High Function associated with isolation of the primary containment is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 3, 8, and 9 valves.

2.c. Standby Gas Treatment (SGT) System Exhaust 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.

The Exhaust Radiation—High signals are initiated from a radiation detector that is located on the ventilation exhaust piping of the SGT System. The signal from the detector is input to an individual monitor whose trip output, after a preselected time delay, is assigned to both isolation channels. Two channels of SGT Exhaust—High Function are available and are required to be OPERABLE to ensure that no single instrument failure other than the sensor/trip output can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Standby Gas Treatment (SGT) System Exhaust Radiation—High (continued)

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding and to ensure offsite doses remain below 10 CFR 20 and 10 CFR 100 limits.

This Function isolates the Group 9 valves.

2.d. 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 USAR 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 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 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.

This Function isolates the Group 2, 3, 8, and 9 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 uncovery can occur. Therefore, the isolation is initiated on high flow to prevent or minimize

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. RCIC Steam Line Flow—High (continued)

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 USAR 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 transmitters 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 10 valves.

3.b. RCIC Steam Line Flow—Timer

The RCIC Steam Line Flow—Timer 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 USAR transient or 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—Timer 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—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. RCIC Steam Line Flow—Timer (continued)

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 10 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 USAR. 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 4.

The RCIC Steam Supply Pressure—Low signals are initiated from four pressure transmitters that are connected to the RCIC steam line. Four 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.

This Function isolates the Group 10 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 USAR. These instruments are included in the TS because of

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d. RCIC Turbine Exhaust Diaphragm Pressure—High (continued)

the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 4.

The RCIC Turbine Exhaust Diaphragm Pressure—High signals are initiated from four pressure transmitters 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 10 valves.

3.e, 3.f, 3.g, 3.h, 3.i. Area Temperature—High

Area Temperatures are provided to detect a leak from the RCIC 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 USAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area Temperature—High signals are initiated from thermocouples that are located in the area that is being monitored. Two instruments for each Function monitor each area. Two channels for each area monitored by the Temperature—High Functions 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, two channels for the RCIC steam line tunnel area, and four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area). 1B

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

3.e, 3.f, 3.g, 3.h, 3.i. Area Temperature—High (continued)

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

These Functions isolate the Group 10 valves.

3.j. Area Temperature—Timer

The RCIC Area Temperature—Timer is provided to ensure RCIC is not isolated if power is lost to the Area Temperature—High Functions control circuits (the control circuits are powered from the RPS logic buses). This Function is not assumed in any USAR transient or accident analysis since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

The Area Temperature—Timer Function delays all Area Temperature—High signals associated with RCIC isolation by use of time delay relays. When an Area Temperature—High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels for Area Temperature—Timer 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 ensure a loss of power to the Area Temperature—High control circuits does not result in an isolation, but not so long as to impact offsite dose calculations.

This Function isolates the Group 10 valves.

3.k. RCIC/RHR Steam Flow—High

RCIC/RHR high steam line flow is provided to detect a break of the common steam line of RCIC and RHR (steam condensing mode) and initiates closure of the RCIC isolation valves. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. Therefore, the isolation is initiated at high flow to prevent or minimize core damage. The isolation action along with the scram function of RPS ensures that the

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BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

3.k. RCIC/RHR Steam Flow—High (continued) 1C

fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any USAR accident or transient analysis since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC/RHR steam line break from becoming bounding.

The RCIC/RHR steam line flow signals are initiated from two differential pressure transmitters that are connected to the steam line. Two channels with one channel in each trip system are available and 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 as the bounding event.

This Function actuates the Group 10 valves.

3.l. RCIC/RHR Steam Flow—Timer 1C

The RCIC/RHR Steam Flow—Timer is provided to prevent false isolations on RCIC/RHR Steam Flow—High during system startup transients and therefore improves system reliability. This Function is not assumed in any USAR transient or 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/RHR Steam Flow—Timer Function delays the RCIC/RHR Steam Flow—High signals by use of time delay relays. When a RCIC/RHR Steam Flow—High signal is generated, the time delay relay delay the tripping of the associated RCIC isolation trip system for a short time. Two channels of RCIC/RHR Steam Flow—Timer 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 systems starts but not so long as to impact offsite dose calculations. 1C

This Function isolates the Group 10 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.m. 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 provides manual isolation capability (when a system initiation signal is present). There is no specific USAR 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 required to be OPERABLE. As noted (footnote (c) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 10 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 10 valve.

4. Reactor Water Cleanup System Isolation

4.a. Differential Flow—High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow is sensed to prevent exceeding offsite doses. A time delay (Function 4.b, described below) is provided to prevent spurious trips during most RWCU operational transients. This Function is not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLE

4.a. Differential Flow—High (continued)

The high differential flow signals are initiated from two differential pressure transmitters that are connected to the inlet (from the reactor vessel) and four differential pressure transmitters from the outlets (to condenser and feedwater) of the RWCU System. The outputs of the transmitters are compared (in two different summers) and the outputs are 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 can preclude the isolation function.

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

This Function isolates the Group 6 and 7 valves.

4.b. Differential Flow—Timer

The Differential Flow—Timer 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 USAR accident or transient analysis, since bounding analyses are performed for large breaks such as MSLBs.

The Differential Flow—Timer Function delays the Differential Flow—High signals by use of time delay relays. When a 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 channels for Differential Flow—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow—Timer Allowable Value is selected to ensure that the MSLB outside containment remains the limiting break for USAR analysis for offsite dose calculations.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.b. Differential Flow—Timer (continued)

This Function isolates the Group 6 and 7 valves.

4.c, 4.d, 4.e. Area Temperature—High

Area 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 USAR, 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 14 thermocouples that provide input to the Area Temperature—High Function (two per area). Fourteen 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, four channels for the pump rooms (two per room), and eight for the reactor building pipe chase areas (two per area).

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

These Functions isolate the Group 6 and 7 valves.

4.f. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.f. Reactor Vessel Water Level—Low Low, Level 2 (continued)

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. 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.

This Function isolates the Group 6 and 7 valves.

4.g. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been manually initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 9). 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 only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7, "SLC System"). Compliance with Reference 10 (NMP2 requires both SLC pumps to be manually started to inject boron) ensures that no single instrument failure can preclude the isolation function.

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 switches.

This Function isolates the Group 6 and 7 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.h. 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 USAR 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 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 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 6 and 7 valves.

5. RHR Shutdown Cooling System Isolation

5.a, 5.d, 5.e. Area Temperature—High

Area Temperature—High is provided to detect a leak from the RHR SDC 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 USAR 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 area that is being monitored. Two instruments for each Function monitor each area/room. Twenty-two channels for Area Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a, 5.d, 5.e. Area Temperature—High (continued)

isolation function. There are four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area). 1 B

The Area 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 5 valves.

5.b. 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.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. 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)

(continued)

BASES

APPLICABLE SAFETY ANANYSES, LCO, and APPLICABILITY

5.b. Reactor Vessel Water Level—Low, Level 3 (continued)

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 5 valves.

5.c. 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 USAR.

The Reactor Vessel Pressure—High signals are initiated from four pressure transmitters. Four channels of Reactor Vessel 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 5 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 USAR 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 four switch and push buttons (with two channels per switch and push button) for the logic, two 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 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 (ie., 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 5 valves.

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

(continued)

BASES

ACTIONS (continued)

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. 11 and 12) 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.

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 MSIVs portion 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 MSL drain valves portion of the MSL isolation Functions and the other isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate a trip signal from the given Function on a valid signal. This

(continued)

BASES

ACTIONS

B.1 (continued)

ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For the MSIVs portion of 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 the MSL drain valves portion of Functions 1.a, 1.b, 1.d, 1.e, and 1.f, this would require one trip system to have two channels, each OPERABLE or in trip. For the MSIVs portion of Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For the MSL drain valves portion of Function 1.c, this would require one trip system to have two channels, associated with each MSL, each OPERABLE or in trip. For the MSIVs portion of Function 1.g, this would require both trip systems to have one channel per area OPERABLE or in trip. For the MSL drain valves portion of Function 1.g, this would require one trip system to have two channels per area, each OPERABLE or in trip. For Functions 2.a, 2.b, 3.c, 3.d, 4.f, and 5.b, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 2.c, 3.a, 3.b, 3.e, 3.f, 3.j, 3.k, 3.l, 4.a, 4.b, 4.c, 4.g, and 5.c, this would require one trip system to have one channel OPERABLE or in trip. For Functions 3.g, 3.h, 3.i, 4.d, 4.e, 5.a, 5.d, and 5.e, each Function consists of channels that monitor several different locations. Therefore, this would require one channel per location (area/room) 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.h, 2.d, 3.m, 4.h, 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 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

(continued)

BASES

ACTIONS

C.1 (continued)

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. Alternatively, 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.

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.

(continued)

BASES

ACTIONS (continued)

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—High 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—High channel is inoperable, the A pump room area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump. For the RWCU Differential Flow—High Function, if a channel is inoperable due solely to a portion of the channel that monitors flow to the condenser being inoperable, then the affected 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).

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 channels. 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 USAR.
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.

(continued)

BASES

ACTIONS (continued)

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(s) 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.

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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation Instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are 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 analyses (Refs. 11 and 12) 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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.2

This Surveillance verifies that, when the Allowable Value for the Main Steam Line Tunnel Lead Enclosure Temperature—High Function is adjusted based on the formula in footnote (b) to Table 3.3.6.1-1, the actual ambient temperature, as measured by the Main Steam Line Tunnel Lead Enclosure Temperature—High Function channels, is greater than or equal to the ambient temperature (T_{amb}) used to adjust the Allowable Value. Only the OPERABLE Main Steam Line Tunnel Lead Enclosure Temperature—High Function channels are required to be verified. As stated in the Note to the SR, the SR is only required to be met when the Allowable Value is adjusted in accordance with Table 3.3.6.1-1, footnote (b), since the normal Allowable Value is based on a sufficiently low ambient temperature that the verification is not necessary.

The Frequency of 12 hours is based on the need to periodically monitor the ambient temperature to ensure the Allowable Value remains valid, and was chosen to coincide with the CHANNEL CHECK Frequency. As required by SR 3.0.1, the SR must also be performed prior to adjusting the Allowable Value, since the Surveillance must be met at all times when the Allowable Value has been adjusted (thus to meet the SR when the Allowable Value has been adjusted, it must actually be performed prior to the adjustment).

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 Frequency of 92 days is based on reliability analyses described in References 11 and 12.

SR 3.3.6.1.4

The calibration of trip units consists of a test to provide a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.4 (continued)

Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 11 and 12.

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.

The Frequency is based on the assumption of a 24 month calibration, interval 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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test. The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. However, failure to meet the 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 acceptance criteria are included in Reference 13.

A Note to the Surveillance states that the response time of the sensors may be assumed to be the design sensor response time and therefore, are excluded from the ISOLATION SYSTEM RESPONSE TIME testing. This is allowed since the sensor response time for the affected Functions (Functions 1.a, 1.b, and 1.c) is a small part of the overall ISOLATION SYSTEM RESPONSE TIME (Ref. 14).

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. USAR, Table 6.2-56.
2. USAR, Section 6.2.
3. USAR, Chapter 15 and Appendix A.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 15.1.3.

(continued)

BASES

REFERENCES (continued)

6. USAR, Section 15.6.4.

7. USAR, Section 15.2.5.

8. USAR, Section 11.3.

9. USAR, Section 9.3.5.2.

10. 10 CFR 50.62.

11. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

12. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

13. Technical Requirements Manual.

14. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

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 100 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 units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) drywell pressure, (c) reactor building above the refuel floor exhaust radiation, and (d) reactor building below the refuel floor exhaust radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation parameters. In addition, manual initiation of the logic, while not required to be OPERABLE by this Specification, is also provided.

For both the Reactor Vessel Water Level—Low Low, Level 2 and Drywell Pressure—High Functions, the secondary containment isolation instrumentation logic receives input from four channels. The output from these channels are arranged into two two-out-of-two trip systems. For both the Reactor Building Above the Refuel Floor Exhaust Radiation—

(continued)

BASES

BACKGROUND (continued)

High and the Reactor Building Below the Refuel Floor Exhaust Radiation—High Functions, the secondary containment isolation instrumentation logic receives input from two channels. The output from these channels are arranged into two one-out-of-one trip systems. In addition to the isolation function, the SGT subsystems are initiated. There are two SGT subsystems with one subsystem being initiated by each trip system. Automatically isolated secondary containment penetrations are isolated by two isolation valves. Each trip system initiates isolation of one of two valves so that operation of either trip system isolates the penetrations.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves 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 3. 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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 transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. 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 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 Instrumentation"), 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) to ensure that offsite dose limits are not exceeded if core damage occurs.

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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure—High (continued)

initiated in order to minimize the potential of an offsite dose release. The isolation and initiation of systems on Drywell Pressure—High 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 USAR 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 transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was 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, 4. Reactor Building Above the Refuel Floor and Reactor Building Below the Refuel Floor Exhaust 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 Exhaust Radiation—High is detected, secondary containment isolation and actuation of the SGT System are initiated to limit the release of fission products as assumed in the USAR safety analyses (Refs. 1 and 2).

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. 4. Reactor Building Above the Refuel Floor and Reactor Building Below the Refuel Floor Exhaust Radiation—High (continued)

Reactor Building Above the Refuel Floor Exhaust Radiation—High signals are initiated from gaseous radiation detectors that are located on the ventilation exhaust ducting coming from the refuel floor. Reactor Building Below the Refuel Floor Exhaust Radiation—High signals are initiated from gaseous radiation detectors that are located on the ventilation exhaust ducting coming from the different areas of the secondary containment below the refuel floor. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Above the Refuel Floor Exhaust Radiation—High Function and two channels of Reactor Building Below the Refuel Floor Exhaust 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 promptly detect gross failure of the fuel cladding.

The Exhaust Radiation—High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are required to be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.

ACTIONS

A Note has been provided to modify the ACTIONS related to secondary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits

(continued)

BASES

ACTIONS (continued)

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 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. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of isolation capability for the associated penetration flow path(s) or a complete loss of initiation capability for the SGT System. A Function is considered to be maintaining

(continued)

BASES

ACTIONS

B.1 (continued)

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 trip systems (Functions 1 and 2), this would require one trip system to have two channels, each OPERABLE or in trip. For the Functions with two one-out-of-one trip systems (Functions 3 and 4), this would require one trip system to have one channel OPERABLE or in trip.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the affected penetration flow path(s) 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. The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem.

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.

(continued)

BASES

ACTIONS

C.1.1, C.1.2, C.2.1, and C.2.2 (continued)

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.

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. 4 and 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.1 (continued)

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

The 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

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 4 and 5.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.4

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.

SR 3.3.6.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing, performed on 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.

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. USAR, Section 15.6.5.

2. USAR, Section 15.7.4.

3. 10 CFR 50.36(c)(2)(ii).

4. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

5. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentations Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Envelope 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 start and direct flow through the control room outdoor air special filter trains and maintain pressurized the main control room envelope 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 or Drywell Pressure—High) or Main Control Room Ventilation Radiation Monitor—High signal, the CREF System is automatically started in the emergency pressurization mode. A portion of the control room envelope air is then recirculated through the charcoal filter, and sufficient outside air is drawn in through the two outside air intakes to keep the control room envelope slightly pressurized with respect to the outside atmosphere.

The CREF System 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 Functions listed above. The Functions are arranged as follows for each trip system. The Reactor Vessel Water Level—Low Low, Level 2 and Drywell Pressure—High are arranged together in a one-out-of-two taken twice logic. The Main Control Room Ventilation Radiation Monitor—High is arranged in a two-out-of-two logic. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a CREF System initiation signal to the initiation logic.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CREF System to maintain the habitability of the control room envelope is explicitly assumed for certain accidents as discussed in the USAR 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.

CREF System 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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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 transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. 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. In addition, the Main Control Room Ventilation Radiation Monitor—High Function provides adequate protection.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 transmitters 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. Main Control Room Ventilation Radiation Monitor—High

High radiation within the common intake duct of the main control room outside air intakes 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 main control room ventilation high radiation is detected (above measured background), the CREF System is automatically initiated in the emergency pressurization mode since this radiation release could result in radiation exposure to control room personnel.

The Main Control Room Ventilation Radiation Monitor—High Function consists of four independent monitors. Four channels of Main Control Room Ventilation Radiation Monitor—High Function are available and are required to be

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Main Control Room Ventilation Radiation Monitor—High (continued)

OPERABLE to ensure that no single instrument failure can preclude CREF System initiation. The Allowable Value was selected to ensure protection of the control room personnel.

The Main Control Room Ventilation Radiation Monitor—High Function is required to be OPERABLE in MODES 1, 2, and 3, and during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel in the secondary containment to ensure that control room personnel are protected during a LOCA, fuel handling event, or a vessel draindown event. During MODES 4 and 5, when these specified conditions are not in progress (e.g., CORE ALTERATIONS), the probability of a LOCA or fuel damage is low; thus, the Function is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to 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.

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.

(continued)

BASES

ACTIONS (continued)

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.

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.

(continued)

BASES

ACTIONS (continued)

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, 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.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

With any Required Action and associated Completion Time not met, the associated CREF subsystem must be placed in the emergency 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. 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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (continued)

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.

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

The calibration of trip units provides a check of the actual trip setpoints. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value. If the trip setting is discovered to be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.3 (continued)

less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 5, 6, and 7.

SR 3.3.7.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.7.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.2, "Control Room Envelope 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.

(continued)

BASES (continued)

REFERENCES

1. USAR, Figure 9.4-4.

2. USAR, Section 6.4.

3. USAR, 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.

B 3.3 INSTRUMENTATION

B 3.3.7.2 Mechanical Vacuum Pump Isolation Instrumentation

BASES

BACKGROUND

The Mechanical Vacuum Pump Isolation Instrumentation initiates a trip of the main condenser mechanical vacuum pumps and isolation of the associated isolation valve following events in which main steam line radiation exceeds predetermined values. Tripping and isolating the mechanical vacuum pumps limits the offsite doses in the event of a control rod drop accident (CRDA).

The Mechanical Vacuum Pump Isolation Instrumentation (Refs. 1 and 2) includes detectors, monitors, and relays that are necessary to cause initiation of a mechanical vacuum pump isolation. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the mechanical vacuum pump isolation logic.

The isolation logic consists of two independent trip systems, with two channels of Main Steam Line Radiation—High in each trip system. Each trip system is a one-out-of-two logic for this Function. Thus, either channel of Main Steam Line Radiation—High in each trip system is needed to trip a trip system. The outputs of the channels in a trip system are combined in a one-out-of-two taken twice logic so that both trip systems must trip to result in an isolation signal.

There is one isolation valve and two mechanical vacuum pump breakers associated with this Function.

APPLICABLE SAFETY ANALYSES

The Mechanical Vacuum Pump Isolation Instrumentation is assumed in the safety analysis for the CRDA. The Mechanical Vacuum Pump Isolation Instrumentation initiates a trip and isolation of the mechanical vacuum pumps to limit offsite doses resulting from fuel cladding failure in a CRDA (Ref. 3).

The mechanical vacuum pump isolation satisfies Criterion 3 of Reference 4.

(continued)

BASES (continued)

LCO

The OPERABILITY of the mechanical vacuum pump isolation is dependent on the OPERABILITY of the individual Main Steam Line Radiation—High instrumentation channels, which must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.7.2.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated isolation valve and mechanical vacuum pump breakers.

An Allowable Value is specified for the Main Steam Line Radiation—High isolation Function specified in the LCO. The nominal trip setpoint is specified in the setpoint calculations. The nominal setpoint is 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 its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The trip setpoint is that predetermined value of output at which an action should take place. The setpoint is compared to the actual process parameter (i.e., main steam line radiation) and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip auxiliary unit) changes state. The analytic limit is derived from the limiting value of the process parameter obtained from the safety analysis. The Allowable Value is derived from the analytic limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoint is derived from the analytical limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoint is also derived from the Allowable Value in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoint is used. In addition, both the Allowable Value and trip setpoint may have additional conservatisms.

APPLICABILITY

The mechanical vacuum pump isolation is required to be OPERABLE in MODES 1 and 2, when any mechanical vacuum pump is in service (i.e., taking a suction on the main condenser)

(continued)

BASES

APPLICABILITY (continued)

and any main steam line not isolated, to mitigate the consequences of a postulated CRDA. In this condition fission products released during a CRDA could be discharged directly to the environment. Therefore, the mechanical vacuum pump isolation is necessary to assure conformance with the radiological evaluation of the CRDA. In MODE 3, 4 or 5 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. When the mechanical vacuum pump is not in service or the main steam lines are isolated in MODE 1 or 2, fission product releases via this pathway would not occur.

ACTIONS

A Note has been provided to modify the ACTIONS related to Mechanical Vacuum Pump 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 Mechanical Vacuum Pump 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 Mechanical Vacuum Pump Isolation Instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with mechanical vacuum pump isolation capability maintained (refer to Required Action B.1 Bases), the Mechanical Vacuum Pump Isolation Instrumentation is capable of performing the intended function. However, the reliability and redundancy of the Mechanical Vacuum Pump Isolation Instrumentation is reduced, such that a single failure in one of the remaining channels could result in the inability of the Mechanical Vacuum Pump Isolation Instrumentation to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities affecting multiple channels, and the low probability of an event requiring the initiation of

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

mechanical vacuum pump isolation, 12 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. (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 isolation valve or mechanical vacuum pump breaker, since this may not adequately compensate for the inoperable valve or breaker (e.g., the valve may be inoperable such that it will not close). 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 loss of condenser vacuum), or if the inoperable channel is the result of an inoperable valve or breaker, Condition C must be entered and its Required Actions taken.

B.1

Condition B is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system result in not maintaining mechanical vacuum pump isolation capability. The mechanical vacuum pump isolation capability is maintained when sufficient channels are OPERABLE or in trip such that the Mechanical Vacuum Pump Isolation Instrumentation will generate a trip signal from a valid Main Steam Line Radiation—High signal, and the isolation valve will close and mechanical vacuum pump breakers will open. This would require both trip systems to have one channel OPERABLE or in trip, and the mechanical vacuum pump isolation valve or mechanical vacuum pump breakers to be OPERABLE.

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.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

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 3 within 12 hours (Required Action C.4). Alternately, the associated mechanical vacuum pump may be removed from service since this performs the intended function of the instrumentation (Required Actions C.1 and C.2). An additional option is provided to isolate the main steam lines (Required Action C.3), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, or to remove the mechanical vacuum pump from service, or to isolate the main steam lines, 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 the associated Conditions and Required Actions may be delayed for up to 6 hours provided mechanical vacuum pump isolation trip capability is maintained. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the 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 mechanical vacuum pumps will trip and isolate when necessary.

SR 3.3.7.2.1

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 parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.1 (continued)

channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

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

SR 3.3.7.2.2

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 5.

SR 3.3.7.2.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.3 (continued)

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.

SR 3.3.7.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breakers and isolation valve is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker or the isolation valve 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 these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Section 7.3.1.1.2.
2. USAR, Section 10.4.2.
3. USAR, Section 15.4.9.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDC-30851-P-A, "Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

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.

Each Division 1, 2 and 3, 4.16 kV Emergency Bus Loss of Voltage Function and Degraded Voltage Function is monitored by three separate undervoltage relays, one relay per phase (Ref. 1). These relay outputs are arranged in a two-out-of-three logic configuration for each division. The 4.16 kV Emergency Bus Undervoltage and Degraded Voltage Function signals provide inputs to their respective Bus Undervoltage and Degraded Voltage—Time Delay Functions. Each Division 1, 2, and 3 emergency bus has one Loss of Voltage—Time Delay relay. The Division 1 and 2 Degraded Voltage Function output utilizes two time delay relays, one time delay for a LOP with a loss of coolant accident (LOCA) signal and the other a LOP without a LOCA signal. The Division 3 Degraded Voltage Function has only one Time Delay Function. When a 4.16 kV Emergency Bus Loss of Voltage or Degraded Voltage Function setpoint has been exceeded and the respective time delay completed, the time delay relay actuates and sends a LOP signal to the respective bus load shedding control scheme, which starts the associated DG, provides a closure signal for the DG output breaker, opens both offsite circuit supply breakers, and for Division 1 and 2 only, sheds all loads on the 4.16 kV emergency bus, including the stub bus (except the 600 V load centers).

(continued)

BASES (continued)

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 based on the loss of offsite power coincident with a LOCA. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of Reference 5.

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 by accounting

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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

4.16 kV Emergency Bus Undervoltage

1.a, 1.b, 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 prior to the voltage on the bus dropping below the minimum Loss of Voltage Function Allowable Value but after the voltage drops below the maximum Loss of Voltage Function Allowable Value (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, but short enough to ensure that power is available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 1.b, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) (continued)

Three channels of Division 1, 2 and 3, 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)—4.16 kV Basis Function per associated emergency bus are available, but only two channels of Loss of Voltage—4.16 kV Basis per 4.16 kV emergency bus is required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Loss of Voltage—Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements ensure that no single instrument failure can preclude the DG function (Since a failure of a required loss of voltage channel or a time delay channel will only impact the ability of one of the three DGs to start, and only two DGs are credited in the accident analyses, the DG function is still maintained). Refer to LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs. C

1.c, 1.d, 1.e, 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 prior to the voltage on the bus dropping below the minimum Degraded Voltage Function Allowable Value but after the voltage drops below the maximum Degraded Voltage Function Allowable Value (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, 2 and 3, 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)—4.16 kV Basis Function

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 1.e, 2.c, 2.d, 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

per associated emergency bus are available, but only two channels of the Degraded Voltage—4.16 kV Basis per 4.16 kV emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of each Division 1 and 2 Degraded Voltage—Time Delay, No LOCA Function and Degraded Voltage—Time Delay, LOCA Function per associated emergency bus, is available and required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of the Division 3 Degraded Voltage—Time Delay Function is available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements ensure that no single instrument failure can preclude the DG function (Since a failure of a required degraded voltage channel or a time delay channel will only impact the ability of one of the three DGs to start, and only two DGs are credited in the accident analyses, the DG function is still maintained). Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs. C

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more required channels of a Function inoperable, the Function may not be 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1

If any Required Action and associated Completion Time is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains LOP initiation capability. LOP initiation capability is maintained provided bus load shedding control scheme can be initiated by the Loss of Voltage or Degraded Voltage Functions for two of the three 4.16 kV emergency buses. 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 adjustment 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

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 a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.3

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. USAR, Section 8.3.1.1.2.
2. USAR, Section 5.2.
3. USAR, Section 6.3.
4. USAR, Chapter 15.
5. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring—Logic

BASES

BACKGROUND

The RPS Electric Power Monitoring—Logic System is provided to isolate the RPS logic bus from the uninterruptible power supply (UPS) set or an alternate AC power supply in the event of overvoltage, undervoltage, or underfrequency. The UPS set can be supplied by the normal AC source or by the backup DC source. This system protects the loads connected to the RPS logic 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 logic buses includes the RPS logic, main steam isolation valve trip solenoids, and various valve isolation logic.

The RPS Electric Power Monitoring—Logic assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two UPS sets or alternate power supplies and will de-energize its respective RPS logic 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—Logic System (e.g., both inseries electric power monitoring assemblies), the RPS logic bus loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the MSIV trip solenoids and other Class 1E devices.

In the event of a low voltage condition, for an extended period of time, the MSIV trip solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of MSIV closure action.

In the event of an overvoltage condition, the RPS and isolation logic relays, as well as the main steam isolation valve trip 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 logic bus and its UPS set or its

(continued)

BASES

BACKGROUND (continued)

alternate power supply. Each of these circuit breakers has an associated independent set of 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 UPS 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 power to the associated RPS logic bus.

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 logic buses can perform its intended function. RPS electric power monitoring provides protection to the RPS (except the scram solenoids) and other systems that receive power from the RPS logic buses, by disconnecting the RPS logic buses from the power supply under specified conditions that could damage the RPS logic bus powered equipment.

RPS Electric Power Monitoring—Logic satisfies Criterion 3 of Reference 2.

LCO

The OPERABILITY of each RPS electric power monitoring assembly (RPS logic bus) 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 RPS logic bus. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly (RPS logic bus) failure can preclude the function of RPS logic bus powered components. Each of the electric power monitoring assembly (RPS logic bus) trip logic setpoints are 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 (RPS logic bus) trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip

(continued)

BASES

LCO (continued)

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 obtained from the safety analysis. The Allowable Values are derived from the analytic limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The Allowable Values for the instrument settings are based on the RPS logic bus providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V (+ 10 V, - 15 V) (to MSIV trip solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the RPS logic buses being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies (RPS logic bus) is essential to disconnect the RPS logic bus powered components from the UPS set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS logic bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies (RPS logic bus) is required when the RPS logic bus powered components are required to be OPERABLE. This results in the RPS Electric

(continued)

BASES

APPLICABILITY (continued)

Power Monitoring—Logic System OPERABILITY being required in MODES 1, 2, and 3, MODES 4 and 5 with both residual heat removal (RHR) shutdown cooling suction isolation valves open, MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, and during operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

A.1

If one RPS electric power monitoring assembly for an RPS logic bus is inoperable, or one RPS electric power monitoring assembly for each RPS logic bus is inoperable, the OPERABLE assembly will still provide protection to the RPS logic bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring—Logic 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, Condition C, D, E, or F, as applicable, must be entered and its Required Actions taken.

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—Logic protection occurring during this period. It also allows time for plant operations personnel to take corrective actions.

B.1

If both power monitoring assemblies for an RPS logic bus are inoperable, or both power monitoring assemblies for each RPS logic bus are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each RPS logic bus. If one inoperable assembly for each RPS logic bus cannot be restored to OPERABLE status, Condition C, D, E, or F, as applicable, must be entered and its Required Actions taken. 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.

(continued)

BASES

ACTIONS (continued)

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 logic bus loads (e.g., scram of control rods and isolation of MSIVs) 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 each RPS logic 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.

(continued)

BASES

ACTIONS (continued)

F.1.1, F.1.2, F.2.1, F.2.2, F.3.1, and F.3.2

If any Required Action and associated Completion Time of Condition A or B are not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, the ability to isolate the secondary containment and start the Standby Gas Treatment (SGT) and Control Room Envelope Filtration (CREF) Systems cannot be ensured. Therefore, actions must be immediately performed to ensure the ability to maintain the secondary containment and CREF System functions. Isolating the affected penetration flow path(s) and starting the associated SGT and CREF subsystems (Required Actions F.1.1, F.2.1, and F.3.1) performs the intended function of the instrumentation the RPS electric power monitoring assemblies is protecting, and allows operations to continue.

Alternatively, immediately declaring the associated secondary containment isolation valves, SGT subsystem, or CREF subsystem inoperable (Required Actions F.1.2, F.2.2, and F.3.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2, LCO 3.6.4.3, and LCO 3.7.2) provide appropriate actions for the inoperable components.

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 RPS logic bus 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.

(continued)

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 184 day Frequency is based on guidance provided in Generic Letter 91-09 (Ref. 3). C

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The 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.

SR 3.3.8.2.3

Performance of a system functional test demonstrates that, with 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. B

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.3 (continued)

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

REFERENCES

1. USAR, Section 8.3.1.1.3.

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."

B 3.3 INSTRUMENTATION

B 3.3.8.3 Reactor Protection System (RPS) Electric Power Monitoring—Scram Solenoids

BASES

BACKGROUND

The RPS Electric Power Monitoring—Scram Solenoids System is provided to isolate the RPS scram solenoid bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the scram solenoids connected to the RPS scram solenoid bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path for the essential safety circuits.

The RPS Electric Power Monitoring—Scram Solenoids assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or alternate power supplies and will de-energize its respective RPS scram solenoid 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—Scram Solenoids System (e.g., both inseries electric power monitoring assemblies), the RPS scram solenoids may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids.

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 scram solenoids may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS scram solenoid bus and its MG set or its alternate power supply. Each of these circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric

(continued)

BASES

BACKGROUND (continued)

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 power to the associated RPS scram solenoid bus.

APPLICABLE SAFETY ANALYSES

RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the scram solenoids can perform their intended function. RPS electric power monitoring provides protection to the scram solenoids by disconnecting the RPS scram solenoid buses from the power supply under specified conditions that could damage the RPS scram solenoids.

RPS Electric Power Monitoring—Scram Solenoids satisfies Criterion 3 of Reference 2.

LCO

The OPERABILITY of each RPS electric power monitoring assembly (RPS scram solenoid bus) 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 RPS scram solenoid bus. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly (RPS scram solenoid bus) failure can preclude the function of RPS scram solenoids. Each of the electric power monitoring assembly (RPS scram solenoid bus) trip logic setpoints are 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 (RPS scram solenoid bus) trip logic (refer to SR 3.3.8.3.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the

(continued)

BASES

LCO (continued)

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 obtained from the safety analysis. The Allowable Values are derived from the analytic limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The Allowable Values for the instrument settings are based on the RPS scram solenoid buses providing ≥ 57 Hz and 115 V ± 10 V to the scram solenoids. The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the RPS scram solenoid buses being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies (RPS scram solenoid bus) is essential to disconnect the RPS scram solenoids 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 scram solenoid bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies (RPS scram solenoids) is required when the RPS scram solenoid bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring—Scram

(continued)

BASES

APPLICABILITY (continued)

Solenoids System OPERABILITY being required in MODES 1 and 2, 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 RPS scram solenoid bus is inoperable, or one RPS electric power monitoring assembly for each RPS scram solenoid bus is inoperable, the OPERABLE assembly will still provide protection to the RPS scram solenoids under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring—Scram Solenoids 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 RPS scram solenoid bus must be removed from service (Required Action A.1). This places the RPS scram solenoid bus in a safe condition.

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—Scram Solenoids 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 RPS scram solenoid bus(es) from service (e.g., as in the case where removing the RPS scram solenoid bus(es) from service would result in a scram), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an RPS scram solenoid bus are inoperable, or both power monitoring assemblies for each RPS scram solenoid bus are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each RPS scram solenoid bus. If one inoperable assembly for each RPS scram solenoid bus cannot be restored to

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE status, the associated RPS scram solenoid bus must be removed from service within 1 hour (Required Action B.1). 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 RPS scram solenoid bus(es) from service (e.g., as in the case where removing the RPS scram solenoid bus(es) from service would result in a scram), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1 or 2, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS scram solenoids (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in 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. This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS scram solenoids (e.g., scram of control rods) is not required.

(continued)

BASES (continued)

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 RPS scram solenoid bus 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.

SR 3.3.8.3.1

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 184 day Frequency is based on guidance provided in Generic Letter 91-09 (Ref. 3). C

SR 3.3.8.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The 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.

SR 3.3.8.3.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3.3 (continued)

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. 1B

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. USAR, Section 8.3.1.1.3.

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."

RELOCATED SPECIFICATIONS

R.1 (cont'd) TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled in accordance with 10 CFR 50.59.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The CTS Tables 3.3.6-1 and 4.3.6-1 Function 6.a, Reactor Mode Switch Shutdown Position (ITS Table 3.3.2.1-1 Function 3), Applicability has been changed from MODES 3 and 4 to include any time the reactor mode switch is in the shutdown position. ITS Table 1.1-1 requires the reactor mode switch to be in the Shutdown position for MODES 3 and 4. Thus, the MODES 3 and 4 requirements ensure that all rods remain inserted when the reactor mode switch is in shutdown. In MODE 5 with the mode switch in shutdown, the control rod withdrawal blocks are assumed in the safety analysis to prevent criticality. Therefore, they must be OPERABLE to fulfill the safety analysis. In addition, the associated CTS Table 3.3.6-1 Action 62 (ITS 3.3.2.1 ACTION E) has been changed from placing the inoperable channel in the tripped condition within 12 hours to immediately suspending all control rod withdrawal and initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. This will ensure the control rods are inserted when the unit is shutdown, as assumed in the accident analysis. This is an additional restriction on plant operation.

M.2 A new RBM Surveillance has been added (proposed SR 3.3.2.1.4) to verify the automatic enabling points of the RBM. This SR ensures that the RBM Functions are not inadvertently bypassed with power level ≥ 30% RTP and a peripheral control rod is not selected. This is an additional restriction on plant operation to ensure the proper operation of the RBM. | A

M.3 The CTS 3.1.4.1 footnote * allows entry into MODE 2 for the purpose of determining RWM Operability before withdrawal of control rods for the purpose of bringing the reactor critical. Also, CTS 4.1.4.1.a and b only require the RWM to be tested prior to the withdrawal of control rods for the purpose of making the reactor critical. The Note to proposed SR 3.3.2.1.1 will require the RWM to be determined Operable (by performing a CHANNEL FUNCTIONAL TEST) within 1 hour after withdrawal of any control rod when RTP is ≤ 10%, not just when the withdrawal is for the purpose of making the reactor critical. This change is necessary to ensure the safety analysis assumptions concerning control rod worth are maintained by ensuring the RWM is Operable during any potential change in control rod worth. This is an additional restriction on plant operation.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A Surveillance has been added (proposed SR 3.3.2.2.1) to perform a CHANNEL CHECK every 24 hours of the feedwater and main turbine high water level trip instrumentation. This will ensure that a gross failure of the instrumentation will not remain undetected. This is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1, and is an additional restriction on plant operation. 1 C

M.2 The allowable outage time specified in CTS Table 3.3.9-1 Action 140.b for two inoperable channels has been decreased from 72 hours to 2 hours in ITS 3.3.2.2 ACTION B, consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. This 2 hour Completion Time is consistent with ITS 3.2.2 since this instrumentation's purpose is to preclude a MCPR violation. This change is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

B

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of CTS 4.3.9.2 (proposed SR 3.3.2.2.4) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. This surveillance ensures the Feedwater System/Main Turbine High Water Level trip function will operate properly during the corresponding transients of the USAR where this function is required such as a Feedwater Controller Failure. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety

A.1

Specification 3.3.4.2

INSTRUMENTATION

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued) L.3

ACTION C e. With both Trip Systems inoperable, restore at least one Trip System to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours. L.4

ACTION D add proposed Required Action D.1

SURVEILLANCE REQUIREMENTS

SRs 3.3.4.2.1, 3.3.4.2.2, 3.3.4.2.5 1C

4.3.4.1.1 Each ATWS-RPT System instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.1-1.

A.4

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

SR 3.3.4.2.6

24 LD.1

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A.1

Specification 3.3.4.2

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

SR 3.3.4.2.5 (C)

TRIP FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
LCO 3.3.4.2.a 1. Reactor Vessel, Water Level - Low Low, Level 2	~~≥ 108.8 in.*~~	≥ 101.8 in.
LCO 3.3.4.2.b 2. Reactor Vessel Pressure - High	~~≤ 1065 psig~~	≤ 1080 psig

L.1

~~* See Bases Figure B3/4 3-1.~~

L.1

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A.1

Specification 3.3.4.2

TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION		SR 3.3.4.2.1 CHANNEL CHECK	SR 3.3.4.2.2 CHANNEL FUNCTIONAL TEST	SR 3.3.4.2.5 CHANNEL CALIBRATION	
LCO 3.3.4.2.a 1.	Reactor Vessel Water Level - Low, Low, Level 2	S	Q	R* (24 months)	1
LCO 3.3.4.2.b 2.	Reactor Vessel Pressure - High	S	Q	R* (24 months)	1

SR 3.3.4.2.3

LE.1

* Perform the calibration procedure for the trip unit setpoint at least once per 92 days. 1

SR 3.3.4.2.3

add proposed SR 3.3.4.2.4

M.2

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DISCUSSION OF CHANGES
ITS: 3.3.4.2 - ATWS-RPT INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 2 current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted that do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1 (i.e., the Improved Standard Technical Specifications (ISTS)).

A.2 This proposed change to the CTS 3.3.4.1 Actions provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.3.4.2 ACTIONS Note ("Separate Condition entry is allowed for each....") provides direction consistent with the intent of the existing Actions for an inoperable ATWS-RPT instrumentation channel. It is intended that each inoperable channel is allowed a certain time to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.3 CTS 3.3.4.1 Action b requires placing the inoperable channels in trip within the required Completion Time. ITS 3.3.4.2 Required Action A.1 has been added to provide an option to restore the channel to Operable status in lieu of tripping the channel. Since restoring the channel is always an option (as described in CTS 3.0.2 and ITS 3.0.2), the addition of this Required Action is administrative.

A.4 CTS 4.3.4.1.2 requires performance of "simulated automatic operation." Verification of the simulated automatic operation is normally conducted with the system functional test. However, for the ATWS-RPT System the only automatic operation required is opening of the recirculation pump trip breakers. Since no separate system functional test is specified, the opening of these breakers is specifically identified and included with the LOGIC SYSTEM FUNCTIONAL TEST of proposed SR 3.3.4.2.6. Since this is only a change in the presentation, this change is considered administrative. 1 C

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 If the channels are inoperable due to a trip breaker that will not open, placing the channels in the tripped condition, as required by CTS 3.3.4.1 Actions b and c.1, will not accomplish the intended restoration of the functional capability. Therefore, a Note is added to ITS 3.3.4.2 Required Action A.2 to prevent proposed Required Action A.2 from being used in these conditions. This new Note will ensure the functional capability of the ATWS-RPT is restored (by restoring the inoperable channel) within the allowed Completion Time when a trip breaker is inoperable and is more restrictive on plant operation.

M.2 A new Surveillance Requirement has been added (proposed SR 3.3.4.2.4) to verify the low frequency motor generator trip portion of the Reactor Vessel Steam Dome Pressure—High Function is not bypassed for > 29 seconds when Thermal Power is > 5% RTP. This SR ensures that the Reactor Vessel Steam Dome Pressure—High Function is not inadvertently bypassed when it is required to trip the low frequency motor generators. This SR represents an additional restriction on plant operation. 1 C 1 C 1 C

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LB.1 The allowed out of service time for CTS 3.3.4.1 Actions b and c.1 is extended from 24 hours to 14 days in ITS 3.3.4.2 Required Action A.2. In addition, the allowed out of service time for CTS 3.3.4.1 Action c.1 footnote * is extended from 78 hours to 14 days in ITS 3.3.4.2 Required Action A.2. (The footnote requires restoration of the channel in 6 hours or the Trip System shall be declared inoperable. Once the Trip System is declared inoperable, CTS 3.3.4.1 Action d allows an additional 72 hours to restore the channel before a unit shutdown is required. Therefore, a total of 78 hours is currently allowed to restore the channel.) Both ATWS trip functions are still capable of tripping both recirculation pumps while in this condition. This allowed out of service time has been shown to maintain an acceptable risk in accordance with previously conducted reliability analysis (GENE-770-06-1-A, December 1992). The logic design of ATWS-RPT instrumentation is bounded by this reliability analysis and the conclusions of the analysis are applicable to the NMP2 design. The results of the NRC review of this generic analysis as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analysis is applicable to NMP2, and that NMP2 meets all requirements of the NRC SER accepting the generic reliability analysis.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of CTS 4.3.4.1.2 (proposed SR 3.3.4.2.6) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. This SR ensures that ATWS-RPT System will function as designed to ensure proper response during an analyzed event. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. Extending the SR interval for this function is acceptable because the ATWS-RPT logic is tested every 92 days by the Channel Functional Test in CTS 4.3.4.1.1 (proposed SR 3.3.4.2.2). This testing of the ATWS-RPT System ensures that a significant portion of the circuitry is operating properly and will detect significant failures of this circuitry. The ATWS-RPT System including the actuating logic is designed to be single failure proof and therefore, is highly reliable. 1 C

Based on the above discussion, the impact, if any, of this change on system availability is small. This historical review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24 month operating cycle. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of CTS 4.3.4.1.1 and Table 4.3.4.1-1 Trip Functions 1 and 2 (proposed SR 3.3.4.2.5) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in 1 C

Table 3.3.6.1-1

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

Function TRIP FUNCTION	LA.2 VALVE GROUPS OPERATED BY SIGNAL(a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM(b)	APPLICABLE OPERATIONAL CONDITION	ACTION
3 2. RCIC Isolation Signals				
3.b a. RCIC Steam Line Flow - High, Timer	10	1	1, 2, 3	22 F
3.c b. RCIC Steam Supply Pressure - Low(g) LA.2	10, 11 R.1	2	1, 2, 3	22 F
3.a c. RCIC Steam Line Flow - High	10	1	1, 2, 3	22 F
3.d d. RCIC Turbine Exhaust Diaphragm Pressure - High(g)	10	2	1, 2, 3	22 F
3.e e. RCIC Equipment Area Temperature - High	10	1	1, 2, 3	22 F
3.f f. RCIC Steam Line Tunnel Temperature - High	10	1	1, 2, 3	22 F
3.m g. Manual Isolation Push Button [RCIC](h) Note(c)	10	1 Note (c) Division I Only	1, 2, 3	26 G
h. Drywell Pressure - High(j)	11(i)	2	1, 2, 3	22 R.1
3.k i. RHR/RCIC Steam Flow - High	10 LA.2	1	1, 2, 3	22 F
3. Secondary Containment Isolation Signals				
a. Reactor Building Above the Refuel Floor Exhaust Radiation - High	(c)(d)	1	1, 2, 3 and **	27
b. Reactor Building Below the Refuel Floor Exhaust Radiation - High	(c)(d)	1	1, 2, 3 and **	27

A.1

A.7 Moved to LCO 3.3.6.2

add proposed Functions 3.j and 3.l M.3

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Specification 3.3.6.1

Table 3.3.6.1-1

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

Function TRIP FUNCTION	TRIP SETPOINT (L.1)	ALLOWABLE VALUE
3 2. RCIC Isolation Signals (Continued)		
3d d. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
3e e. RCIC Equipment Area Temperature - High	≤ 135°F	≤ 140.5°F
3f f. RCIC Steam Line Tunnel Temperature - High	≤ 135°F	≤ 140.5°F
3.M g. Manual Isolation Push Button (RCIC)	NA	NA
h. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig (R.1)
3.k i. RHR/RCIC Steam Flow - High	≤ 37.4 in. H_2O (L.1)	≤ 40.73 in. H_2O
3. Secondary Containment Isolation Signals		
a. Reactor Building Above the Refuel Floor Exhaust Radiation - High	≤ 2.36×10^{-3} μCi/cc	≤ 2.46×10^{-3} μCi/cc
b. Reactor Building Below the Refuel Floor Exhaust Radiation - High	≤ 2.36×10^{-3} μCi/cc	≤ 2.46×10^{-3} μCi/cc

add proposed Functions 3.j and 3.l (M.3)

* See Bases Figure B3/4 3-1. (A.11)

(A.7) moved to LCO 3.3.6.2

(A.1)

Specification 3.3.6.1

Amendment No. 4

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(C)

Table 3.3.6.1-1

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Function TRIP FUNCTION		SR3.3.6.1.1 CHANNEL CHECK	SR3.3.6.1.3 CHANNEL FUNCTION TEST	SR3.3.6.1.5 CHANNEL CALIBRATION (LE.1) All R channel calibrations	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
3. 2.	RCIC Isolation Signals				
3.b a.	RCIC Steam Line Flow - High, Timer	NA	Q	R	1, 2, 3
3.c b.	RCIC Steam Supply Pressure - Low	S	Q	R(a) SR3.3.6.1.4	1, 2, 3
3.a c.	RCIC Steam Line Flow - High	S	Q	R(a)	1, 2, 3
3.d d.	RCIC Turbine Exhaust Diaphragm Pressure - High	S	Q	R(a)	1, 2, 3
3.e e.	RCIC Equipment Area Temperature - High	S	Q	R(b) A.13	1, 2, 3
3.f f.	RCIC Steam Line Tunnel Temperature - High	S	Q	R(b)	1, 2, 3
3.m g.	Manual Isolation Pushbutton (RCIC)	NA	Q(C) A.15	NA	1, 2, 3
h.	~~Drywell Pressure - High~~	~~S~~	~~Q~~	~~R(a)~~	~~1, 2, 3~~ R.1
3.k i.	RHR/RCIC Steam Flow - High	S	Q	R(a) SR3.3.6.1.4	1, 2, 3
3.	Secondary Containment Isolation Signals				
a.	Reactor Building Above the Refuel Floor Exhaust Radiation - High	NA	Q	R	1, 2, 3, and †
b.	Reactor Building Below the Refuel Floor Exhaust Radiation - High	NA	Q	R	1, 2, 3, and †

A.7 Moved to LCO3.3.6.2

add proposed Functions 3.j and 3.l M.3

A.1

Specification 3.3.6.1

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TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The CTS Tables 3.3.2-1 and 4.3.2.1-1 Trip Function 1.a.3 Applicability for the Reactor Vessel Water Level — Low, Level 3 Function has been changed to include MODES 4 and 5. This Function isolates the RHR Shutdown Cooling (SDC) System valves (Group 5) and these new Applicabilities will protect against potential draining of the reactor vessel through the RHR SDC suction line during shutdown conditions, which is when the RHR SDC System is normally operated. In addition, when RHR System integrity is maintained in MODES 4 and 5, only one of the two low water level instrumentation trip systems will be required. This is provided in ITS Table 3.3.6.1-1 Note (d). With the piping intact and no maintenance being performed that has a potential for draining the reactor vessel through the RHR System, both trip systems are not required since one trip system can isolate the suction piping (by closing one of the suction isolation valves). An appropriate ACTION (ITS 3.3.6.1 ACTION J) has also been added for when the channel(s) of the Function is inoperable in MODES 4 and 5. This is an additional restriction on plant operations and is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

M.2 The number of required channels for the Groups 3, 6, and 7 PCIV Manual Initiation Function (CTS Table 3.3.2-1 Trip Function 1.m) has been increased from "1" per trip system to "4" per trip system in ITS Table 3.3.6.1-1 Functions 2.d and 4.h. The design of the Groups 3, 6, and 7 logic is two switch and push buttons per trip system, with both being required to actuate a trip system. Currently, only one switch and push button per trip system is required. Therefore, this part of the change is more restrictive on plant operation and will ensure these groups can be manually actuated. In addition, each of the switch and push button channels provides two inputs to the isolation logic; one input actuated by rotating a collar switch and a second input by depressing the inner push button. Therefore, using the ITS format that each input is considered a channel, the minimum channels is more appropriately specified as "4." Since this part of the change involves no design change but is only a difference in nomenclature, it is considered administrative.

M.3 Two additional Functions have been added, ITS Table 3.3.6.1-1 Functions 3.j and 3.l. These Functions are Timer Functions that delay initiation of the RCIC Area Temperature—High and RHR/RCIC Steam Flow — High Functions. Currently, the RCIC Area Temperature—High and RHR/RCIC Steam Flow — High Functions isolate the RCIC PCIVs only after a time delay. The actual time delay Allowable Values are currently controlled in plant procedures and are based on NRC approved methodology. Appropriate ACTIONS and Surveillance Requirements have also been added. These changes are an additional restriction on plant operation. C

A.2

Loss of Power

Table 3.3.8.1-1
TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

<See Discussion of Changes for ITS: 3.3.5.1, "ECCS Instrumentation", in this Section>

Function TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
C. Division III Trip System			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Level 2	4(b)	1, 2, 3, 4^, 5^	36
b. Drywell Pressure - High (d)	4(b)	1, 2, 3	36
c. Reactor Vessel Water Level - High, Level 8	4(e)	1, 2, 3, 4^, 5^	32
d. Pump Suction Pressure - Low (Transfer)	2(f)	1, 2, 3, 4^, 5^	37
e. Suppression Pool Water Level - High	2(f)	1, 2, 3, 4^, 5^	37
f. HPCS System Flow Rate - Low (Bypass)	1	1, 2, 3, 4^, 5^	31
g. Pump Discharge Pressure - High (Bypass)	1	1, 2, 3, 4^, 5^	31
h. Manual Initiation (d)	1/System	1, 2, 3, 4^, 5^	35

A.1

LA.2

		TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
1.	**D. Loss of Power (Divisions I & II)**						
1.a	1. 4.16-kV Emergency Bus Under-voltage - Loss of Voltage	3/Bus	2/Bus	2/Bus	1, 2, 3, 4^^, 5^^	39 A	1C
1.c	2. 4.16-kV Emergency Bus Under-voltage - Degraded Voltage	3/Bus	2/Bus	2/Bus	1, 2, 3, 4^^, 5^^	39 A	1C
2.	**E. Loss of Power, Division III**						
2.a	1. 4.16-kV Emergency Bus Under-voltage - Loss of Voltage	3/Bus	2/Bus	2/Bus	1, 2, 3, 4^^, 5^^	39 A	1C
2.c	2. 4.16-kV Emergency Bus Under-voltage - Degraded Voltage	3/Bus	2/Bus	2/Bus	1, 2, 3, 4^^, 5^^	39 A	1C

L.2 M.1

Amendment No. 13

add proposed Functions 1.b, 1.d, 1.e, 2.b, and 2.d A.3

1C

Specification 3.3.8.1

A.2 LOP

Table 3.3.8.1-1

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

Function TRIP FUNCTION	TRIP SETPOINT (L.1)	ALLOWABLE VALUE
C. Division III Trip System	See Discussion of Changes for ITS: 3.3.5.1, "ECCS Instrumentation", in this Section.	
1. HPCS SYSTEM		
a. Reactor Vessel Water Level - Low, Low, Level 2	≥108.8 in.*	≥101.8 in.
b. Drywell Pressure - High	≤1.68 psig	≤1.38 psig
c. Reactor Vessel Water Level - High, Level 8	≤202.3 in.*	≤209.3 in.
d. Pump Suction Pressure - Low (Transfer)	≥97 in. H_2O	≥94.5 in. H_2O
e. Suppression Pool Water Level - High	≤201.0 ft. el	≤201.1 ft. el
f. HPCS System Flow Rate - Low (Bypass)	≥825 gpm	≥750 gpm
g. Pump Discharge Pressure - High (Bypass)	≥240 psig	≥220 psig
h. Manual Initiation	NA	NA
1. D. Loss of Power (Divisions I & II)		
1. 4.16-kV Emergency Bus Under-voltage - Loss of Voltage	1.a a. 4.16-kV basis ≥3148 (L.1)	≥3051 (2950) (L.8) volts and ≤3468 (M.2) volts
	1.b b. ≤3.06-sec time delay	≤8.12 (3.20) (L.8) -sec time delay and ≥2.80 (M.2) seconds
2. 4.16-kV Emergency Bus Under-voltage - Degraded Voltage	1.c a. 4.16-kV basis - 3847 volts	≥3770 (3820) (M.2) volts and ≤3898 (M.2) volts
	1.d b. ≤8.16-sec time delay (L.5)	≤8.02 (6) (L.8) -sec time delay and ≥7.4 (M.2) seconds
	1.e c. ≤30.6-sec time delay (L.5)	≤30.2 (2) (L.8) -sec time delay and ≥27.8 (M.2) seconds

A.1

Specification 3.3.8.1

A2 LOP

Table 3.3.8.1-1
TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

Function TRIP FUNCTION		TRIP SETPOINT (L.1)	ALLOWABLE VALUE
2. E. Loss of Power (Division III)			
1. 4.16-kV Emergency Bus Under-voltage - Loss of Voltage	2.a	a. 4.16-kV basis - ≥3148 volts	L.8 2950 and ≤3468 volts (M.2); ≥3051 volts
	2.b	b. ≤3.06-sec time delay	≤3.12 (L.8) sec time delay and ≥2.8 seconds (M.2)
2. 4.16-kV Emergency Bus Under-voltage - Degraded Voltage	2.c	a. 4.16-kV basis - ≥3847 volts	M.2 3820 and ≤3876 volts; ≥3770 volts
	2.d	b. ≤12.24-sec time delay	≤12.48 (L.8) 13.0 sec time delay and ≥11.0 seconds (M.2)

A.1

See Discussion of Changes for ITS: 3.3.5.1, "ECCS Instrumentation," in this Section.

* See Bases Figure B3/4 3-1.

** Alarm only without LOCA signal present; Alarm and trip with LOCA signal present. (L.5)

Functionl.e

Specification 3.3.8.1

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Amendment No. 13

LOP A.2

Table 3.3.8.1-1
TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Function TRIP FUNCTION	CHANNEL CHECK	SR 3.3.8.1.1 CHANNEL FUNCTIONAL TEST	SR 3.3.8.1.2 CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED	
1. D. Loss of Power (Divisions I & II)				M.1	
1a 1. 4.16-kV Emergency Bus Undervoltage - Loss of Voltage	S	M	R	1, 2, 3, 4†, 5†	C
1c 2. 4.16-kV Emergency Bus Undervoltage - Degraded Voltage	S	M	R	1, 2, 3, 4†, 5†	C
2. E. Loss of Power (Division III)					
2a 1. 4.16-kV Emergency Bus Undervoltage - Loss of Voltage	S	M	R	1, 2, 3, 4†, 5†	C A.1
2c 2. 4.16-kV Emergency Bus Undervoltage - Degraded Voltage	S	M	R	1, 2, 3, 4†, 5†	C
	L.b		24 months LE.1		C

add proposed Functions 1.b, 1.d, 1.e, 2.b, and 2.d M.3

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Specification 3.3.8.1

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.3 Five additional Functions have been added, ITS Table 3.3.8.1-1 Functions 1.b, 1.d, 1.e, 2.b, and 2.d. These Functions are Timer Functions which delay initiation of the 4.16 kV Emergency Bus Undervoltage - Loss of Voltage and 4.16 kV Emergency Bus Undervoltage - Degraded Voltage Functions for Divisions I, II, and III. Currently, the 4.16 kV Emergency Bus Undervoltage - Loss of Voltage and 4.16 kV Emergency Bus Undervoltage - Degraded Voltage Functions for Divisions I, II, and III actuate only after a time delay. While the Allowable Values for these Timers are in CTS Table 3.3.3-2, they are not currently considered to be part of the "channel". This is because the channel loses its identity prior to reaching the time delay relays, which are considered to be part of the logic. Therefore, the Surveillances required by CTS Table 4.3.3.1-1 to be performed on the loss of voltage and degraded voltage channels do not include the timers. The logic (including the timers) is completely tested during the LOGIC SYSTEM FUNCTIONAL TEST and the time delay relays are required for instrumentation Operability. An appropriate Surveillance Requirement to perform a CHANNEL CALIBRATION has also been added. The proposed 24 month CHANNEL CALIBRATION Frequency is accounted for in the ITS Allowable Values for the Timer Functions. This change is an additional restriction on plant operation. C

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The detail in CTS 4.3.3.2 relating to methods (simulated automatic operation) for performing the LOGIC SYSTEM FUNCTIONAL TEST is proposed to be relocated to the Bases. This detail is not necessary to ensure the OPERABILITY of the loss of power instrumentation. The requirements of ITS 3.3.8.1 and proposed SR 3.3.8.1.4 are adequate to ensure the loss of power instruments are maintained OPERABLE. Therefore, the relocated detail is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.2 System design details in CTS Table 3.3.3-1 are proposed to be relocated to the Bases. Details relating to system design (the total number of channels provided in the design and the number of channels required to generate a trip) are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the loss of power instrumentation. The requirements of ITS 3.3.8.1 and the associated Surveillance Requirements are adequate to ensure the loss of power instruments are maintained OPERABLE. Therefore, the relocated details are not required to be in the ITS to provide adequate

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of CTS 4.3.3.2 has been extended from 18 months to 24 months in proposed SR 3.3.8.1.4. This SR ensures that LOP Instrumentation logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. The LOP instrumentation including the actuating logic is designed to be single failure proof and therefore, is highly reliable. Major deviations in the circuitry will be discovered during the cycle since the CHANNEL FUNCTIONAL TEST of both the loss of voltage and degraded voltage relays is performed more frequently. 6

Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, on system availability is small as a result of the change in the surveillance test interval. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION of CTS 4.3.3.1 has been extended from 18 months to 24 months in proposed SR 3.3.8.1.3. This SR ensures that LOP Instrumentation will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

Extending the SR Frequency is acceptable because the electrical power sources along with the LOP initiation logic are designed to be single failure proof and therefore are highly reliable. Major deviations in the circuitry will be discovered during the cycle since the CHANNEL FUNCTIONAL TEST of both the loss of voltage and the degraded voltage instrumentation relays is performed more frequently. Furthermore, the impacted LOP instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs, listed by CTS Trip Function number, identify by make, manufacturer and model number the drift evaluations performed: 1C

Trip Functions D.1 and E.1: 4.16 kV Emergency Bus Undervoltage — Loss of Voltage 1C

This function is performed by General Electric Type NGV relays. The GE relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Functions D.2 and E.2: 4.16 kV Emergency Bus Undervoltage — Degraded Voltage 1C

This function is performed by ITE Type 27-H relays. The ITE relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

1C

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A.1

Specification 3.3.8.2

ELECTRICAL POWER SYSTEMS

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (RPS LOGIC)

LIMITING CONDITIONS FOR OPERATION

LCO 3.3.8.2

3.8.4.4 Two RPS UPS electrical protection assemblies for each ~~inservice UPS set or alternate source~~ RPS logic bus shall be OPERABLE. A.2

APPLICABILITY: At all times. L.1

ACTION: A.2

ACTION A a. With one RPS electrical protection assembly for an ~~inservice~~ RPS ~~UPS~~ logic bus inoperable, restore the inoperable electrical protection assembly to OPERABLE status within 72 hours ~~or remove the associated RPS UPS from service~~. M.1

ACTION B b. With both RPS electrical protection assemblies for an ~~inservice~~ RPS ~~UPS~~ logic bus inoperable, restore at least one electrical protection assembly to OPERABLE status within ~~30~~ 1 hour ~~minutes~~ ~~or remove the associated RPS UPS from service~~. A.2 L.2 M.1

add proposed ACTION C A.3

add proposed ACTIONS D, E, and F L.5 B

SURVEILLANCE REQUIREMENTS

add proposed Surveillance Requirements Note L.3

4.8.4.4 The above specified RPS electrical protection assemblies instrumentation shall be determined OPERABLE:

SR 3.3.8.2.1 a. At least once every 6 months by performance of a CHANNEL FUNCTIONAL TEST. C

SR 3.3.8.2.2 b. At least once per ~~18~~ 24 months by demonstrating the OPERABILITY of overvoltage, undervoltage and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints. LD.1 and LE.1

SR 3.3.8.2.2

1. Overvoltage Bus A: ≤ ~~132~~ 133.8 volts AC L.4
   Bus B: ≤ ~~132~~ 133.8 volts AC
2. Undervoltage Bus A: ≥ ~~115.5~~ 115.5 volts AC with time delay set to ≤ 4 seconds M.3
   Bus B: ≥ ~~115.75~~ 114.2 volts AC
3. Underfrequency ≥ ~~57~~ 57.5 Hz M.4

Page 1 of 1

A.1

Specification 3.3.8.3

ELECTRICAL POWER SYSTEMS

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (SCRAM SOLENOIDS)

LIMITING CONDITIONS FOR OPERATION

RPS scram solenoid bus A.2

LCO 3.3.8.3

3.8.4.5 Two RPS electrical protection assemblies (EPAs) for each inservice RPS MG set or alternate source shall be OPERABLE.

APPLICABILITY: At all times L.1

ACTION:

RPS scram solenoid bus A.2

ACTION A

a. With one RPS electrical protection assembly for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable EPA to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service. A.3 scram solenoid bus

RPS scram solenoid bus A.2

ACTION B

b. With both RPS electrical protection assemblies for an inservice RPS MG set or alternate power supply inoperable, restore at least one EPA to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service. A.3 scram solenoid bus

1 hour

add proposed ACTION C L.2

add proposed ACTION D A.4

SURVEILLANCE REQUIREMENTS L.5 B

add proposed Surveillance Requirements Note L.3

4.8.4.5 The above specified RPS electrical protection assemblies shall be determined OPERABLE:

SR 3.3.8.3.1 a. At least once every 6 months by performance of a CHANNEL FUNCTIONAL TEST. C

SR 3.3.8.3.2 b. At least once per 18 months by demonstrating the OPERABILITY of overvoltage, undervoltage and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints. 24 L.D.1 and L.E.1

SR 3.3.8.3.3

L.4

SR 3.3.8.3.2

1. Overvoltage Bus A: ≤ 128.8 volts AC4 (130.5)
   Bus B: ≤ 130.0 volts AC4 (131.7)
2. Undervoltage Bus A: ≥ 114.8 volts AC4 (113.0)
   Bus B: ≥ 115.1 volts AC4 (113.6)
3. Underfrequency ≥ 57 Hz (57.5)

with time delay set to ≤ 4 seconds M.2

M.3

Page 1 of 1

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
<4.1.4.1.a> <4.1.4.1.b> <4.1.4.1 * footnote> SR 3.3.2.1.~~2~~ (1) (4)	NOTE Not required to be performed until 1 hour after any control rod is withdrawn at ≤ ~~[10]~~% RTP in MODE 2. (3) Perform CHANNEL FUNCTIONAL TEST.	(3) ~~[92]~~ days
<4.1.4.1.a> <4.1.4.1.c> SR 3.3.2.1.~~3~~ (2) (4)	NOTE Not required to be performed until 1 hour after THERMAL POWER is ≤ ~~[10]~~% RTP in MODE 1. (3) Perform CHANNEL FUNCTIONAL TEST.	(3) ~~[92]~~ days
(4) Insert SR 3.3.2.1.3 from previous page		
<DOC M.2> SR 3.3.2.1.4	NOTE Neutron detectors are excluded. Verify the RBM is not bypassed when THERMAL POWER is ≥ 30% RTP and a peripheral control rod is not selected. (5) ~~a. Low Power Range—Upscale Function is not bypassed when THERMAL POWER is ≥ 29% and ≤ 64% RTP.~~ ~~b. Intermediate Power Range—Upscale Function is not bypassed when THERMAL POWER is > 64% and ≤ 84% RTP.~~ ~~c. High Power Range—Upscale Function is not bypassed when THERMAL POWER is > 84% RTP.~~	(3) (24) ~~[18]~~ months
<DOC M.5> SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ ~~[10]~~% RTP. (3)	[18] months (24) (3)

(continued)

Insert Page 3.3-19 d.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	~~{92}~~ days 3
SR 3.3.4.2.3	Calibrate the analog trip ~~units~~ modules.	~~{92}~~ days 3
SR 3.3.4.2.4	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level—Low Low, Level 2: ≥ ~~{43.8}~~ 101.8 inches; and 3 b. Reactor Vessel Steam Dome Pressure—High: ≤ ~~{1102}~~ 1080 psig. 3	~~{18}~~ 24 months 3
SR 3.3.4.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	~~{18}~~ 24 months 3
SR 3.3.4.2.4	Verify, for the Reactor Vessel Steam Dome Pressure—High Function, the low frequency motor generator trip is not bypassed for > 29 seconds when THERMAL POWER is > 5% RTP.	24 months 4

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.3.4.2 - ATWS-RPT INSTRUMENTATION

1. The proper NMP2 plant specific nomenclature/value/design requirements have been provided.

2. The NMP2 design includes both fast speed and slow speed breakers for the recirculation pumps. If the ATWS-RPT instrumentation is inoperable solely due to one of the breakers, only the inoperable breaker needs to be removed from service to complete the safety function, not the entire recirculation pump. Therefore ISTS 3.3.4.2 Required Action D.1 has been modified to require the removal of the associated "breaker(s)" from service. If both breakers are affected, then both will continue to be required to be removed from service, consistent with the ISTS Required Action.

3. The brackets have been removed and the proper plant specific information/value has been provided.

4. The NMP2 design of the ATWS-RPT System is different than that described in the ISTS Bases. When a Reactor Vessel Steam Dome Pressure—High trip signal occurs, only the fast speed breakers of the recirculation pumps are immediately tripped. The low frequency motor generators are not tripped on a Reactor Vessel Steam Dome Pressure—High trip signal until after a time delay and only if the associated APRM is still indicating not downscale. Therefore, a new Surveillance Requirement has been added (ITS SR 3.3.4.2.4) to verify the low frequency motor generator trip portion of the Reactor Vessel Steam Dome Pressure—High Function is not bypassed for > 29 seconds when Thermal Power is > 5% RTP. This SR ensures that the Reactor Vessel Steam Dome Pressure—High Function is not inadvertently bypassed when it is required to trip the low frequency motor generators. The following Surveillance Requirements have been renumbered to reflect this addition. C 1C

<TS>
<T 3.3.2-1>
<T 3.3.2-2>
<DOC M3>
<T 4.3.2.1-1>

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. RCIC System Isolation (continued)					
RCIC a. ~~Main~~ Steam Line Tunnel ~~Ambient~~ Temperature - High	1,2,3	~~[1]~~	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ ~~[150]~~ °F
~~h. Main Steam Line Tunnel Differential Temperature - High~~	~~1,2,3~~	~~[1]~~	~~F~~	~~SR 3.3.6.1.1~~ ~~SR 3.3.6.1.2~~ ~~SR 3.3.6.1.5~~ ~~SR 3.3.6.1.6~~	~~≤ [164] °F~~
~~i. Main Steam Line Tunnel Temperature Timer~~	~~1,2,3~~	~~[1]~~		~~SR 3.3.6.1.2~~ ~~SR 3.3.6.1.6~~ ~~SR 3.3.6.1.6~~	~~≤ [30] minutes~~
~~j.~~ RHR Equipment Room ~~Ambient~~ ~~Area~~ Temperature - High	1,2,3	[1 per room]	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ ~~[125]~~ °F
~~k. RHR Equipment Room Differential Temperature - High~~	~~1,2,3~~	~~[1 per room]~~	~~F~~	~~SR 3.3.6.1.1~~ ~~SR 3.3.6.1.2~~ ~~SR 3.3.6.1.5~~ ~~SR 3.3.6.1.6~~	~~≤ [102] °F~~
~~l.~~ RCIC/RHR Steam ~~Line~~ Flow - High	1,2,3	~~[1]~~	F	SR 3.3.6.1.1 SR 3.3.6.1.2 ~~SR 3.3.6.1.3~~ SR 3.3.6.1.5 SR 3.3.6.1.6	≤ ~~[45]~~ inches water
~~m. Drywell Pressure - High~~	~~1,2,3~~	~~[1]~~	~~F~~	~~SR 3.3.6.1.1~~ ~~SR 3.3.6.1.2~~ ~~SR 3.3.6.1.3~~ ~~SR 3.3.6.1.5~~ ~~SR 3.3.6.1.6~~ ~~SR 3.3.6.1.7~~	~~≤ [1.44] psig~~
~~n.~~ Manual Initiation	1,2,3	~~[2]~~ (c)	G	SR 3.3.6.1.6	NA
4. Reactor Water Cleanup (RWCU) System Isolation					
a. Differential Flow - High	1,2,3	~~[1]~~	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 ~~SR 3.3.6.1.7~~	≤ ~~[87]~~ gpm
b. Differential Flow - Timer	1,2,3	~~[1]~~	F	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ ~~[45]~~ seconds

(continued)

INSERT 3.h, 3.i, 3.j

INSERT 3.l

(c) Only inputs into one of the two trip systems

(4) INSERT 3.h, 3.i, 3.j

(CTS)
(T3.3.2-1)
(3.3.2-2) h.
(DOC M.3)
(T4.3.2.1-1)

	Reactor Building Pipe Chase Area Temperature — High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6		
	El. ≈ 319 ft.					≤ 144.5°F	
	El. ≈ 292 ft.					≤ 140.5°F	
	El. ≈ 266 ft.					≤ 140.5°F	
	El. ≈ 206 ft.					≤ 140.5°F	
i.	Reactor Building General Area Temperature — High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 134°F	
j.	Area Temperature — Timer	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.15 seconds	C

(4) INSERT 3.l

l.	RCIC/RHR Steam Flow — Timer	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 13 seconds	C

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.3.6.1 - PRIMARY CONTAINMENT ISOLATION INSTRUMENTATION

1. The proper Primary Containment Isolation Functions that are common to the RPS Instrumentation have been provided. In addition, since all installed primary containment isolation channels required by this LCO are listed in Table 3.3.6.1-1, the word "required" is not needed in Condition A.

2. Editorial change made to be consistent with other similar requirements in the ITS or for clarity.

3. The Standby Gas Treatment System Exhaust Radiation — High Function (ITS Table 3.3.6.1-1 Function 2.c, ISTS Table 3.3.6.1-1 Function 2.g) is not currently required nor needed for primary containment isolation in MODES other than MODES 1, 2, and 3. Therefore, this requirement (ISTS Table 3.3.6.1-1 Note (b)) has been deleted. The associated ACTION (ISTS ACTION K) has also been deleted.

4. Nine new Primary Containment Isolation Functions have been added (ITS Table 3.3.6.1-1 Functions 1.g, 3.h, 3.i, 3.j, 3.l, 4.e, 5.d, 5.e, and 5.f, consistent with current NMP2 Licensing Basis. ITS SR 3.3.6.1.2 has also been added since it is required by ITS Table 3.3.6.1-1 Function 1.g (also consistent with current licensing basis). In addition, 17 Functions have been deleted (ISTS Table 3.3.6.1-1 Functions 2.c, 2.d, 2.e, 2.f, 3.f, 3.h, 3.i, 3.k, 3.m, 4.d, 4.f, 4.g, 4.h, 4.i, 4.j, 5.b, and 5.e) since they are not applicable to NMP2. The Functions and Surveillance Requirements have been renumbered where applicable, to reflect these additions and deletions. 10

5. The brackets have been removed and the proper plant specific information/value has been provided.

6. The current NMP2 Licensing Basis does not require a CHANNEL FUNCTIONAL CALIBRATION to be performed every 92 days. Therefore, ISTS SR 3.3.6.1.4 has been deleted. This surveillance was designated for the RWCU differential flow timer. Current NMP2 Licensing Basis for this function includes a CHANNEL FUNCTIONAL TEST every 92 days and a CHANNEL CALIBRATION on a 18 month frequency. These SRs and frequencies have proven to be more than adequate to ensure operability during the cycle. (The calibration is proposed to be extended to 24 months. See Discussion of Changes).

7. A Note has been added to ITS SR 3.3.6.1.7 to exempt measuring the sensor response times, for Functions 1.a, 1.b, and 1.c (Main Steam Line (MSL) Isolation Reactor Vessel Water Level — Low Low Low, Level 1, Main Steam Line Pressure — Low, and Main Steam Line Flow — High Functions. Deletion of the response time testing for these sensors was evaluated in NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined acceptable since other Technical Specification Surveillances (CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, and LOGIC SYSTEM FUNCTIONAL TEST) ensure that instrumentation response times are within acceptable limits. These other tests are normally sufficient to identify

<CTS>
<T 3.3.3-1>
<T 3.3.3-2>
<T 4.3.3.1-1>
<DOCM.3>

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

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Divisions 1 and 2 – 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ V and ≤ V
b. Loss of Voltage – Time Delay		SR 3.3.8.1.1 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ seconds and ≤ seconds
c. Degraded Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ V and ≤ V
d. Degraded Voltage – Time Delay, NoLOCA		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.6	≥ seconds and ≤ seconds
2. Division 3 – 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ V and ≤ V
b. Loss of Voltage – Time Delay		SR 3.3.8.1.1 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ seconds and ≤ seconds
c. Degraded Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.5 SR 3.3.8.1.6	≥ V and ≤ V
d. Degraded Voltage – Time Delay		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.6	≥ minutes and ≤ minutes
e. Degraded Voltage – Time Delay, LOCA		SR 3.3.8.1.1 SR 3.3.8.1.4 SR 3.3.8.1.6	≥ seconds and ≤ seconds

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
	AND	
	D.2.1 Initiate action to restore one electric power monitoring assembly to OPERABLE status for each RPS logic bus.	Immediately
	OR	
	D.2.2 Initiate action to isolate the Residual Heat Removal Shutdown Cooling System. RHR SDC	Immediately

INSERT ACTION F

<Insert SR NOTE>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	NOTE Only required to be performed prior to entering MODE 2 or 3 from MODE 4, when in MODE 4 for ≥ 24 hours.	
	Perform CHANNEL FUNCTIONAL TEST.	184 days

(continued)

8. (continued)

associated RPS logic bus is OPERABLE. The 6 hour testing allowance has been granted by the NRC in Technical Specification amendments for Georgia Power Company's Hatch Unit 1 (amendment 185) and Unit 2 (amendment 125) and Washington Public Power Supply System Unit 2 (amendment 149, the ITS amendment). The NRC has also granted this allowance in other topical reports for the RPS, ECCS, and isolation instrumentation.

9. The Note to ISTS SR 3.3.8.2.1 has been deleted since the design of the NMP2 RPS logic bus electric power monitoring assemblies allows their testing without de-energizing the RPS logic bus. This design was implemented during the last refueling outage and the deletion is consistent with a recent license amendment change (Amendment 86 issued March 18, 1999). C

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
	AND	
	D.2.1 Initiate action to restore one electric power monitoring assembly to OPERABLE status for inservice power supply(s) supplying required instrumentation.	Immediately
	OR	
	D.2.2 Initiate action to isolate the Residual Heat Removal Shutdown Cooling System.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	NOTE Only required to be performed prior to entering MODE 2 or 3 from MODE 4, when in MODE 4 for ≥ 24 hours.	
	Perform CHANNEL FUNCTIONAL TEST.	184 days

(continued)

INSERT PAGE 3.3-85b

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.3.8.3 - RPS ELECTRICAL POWER MONITORING — SCRAM SOLENOIDS

1. An additional Specification is proposed since the electric supply to the scram solenoids and RPS logic are different. ISTS 3.3.8.2 of the BWR/6 ISTS (NUREG-1434, Rev. 1) has been used in the development of ITS 3.3.8.2 and ITS 3.3.8.3 for NMP2. In addition, the requirements have been renumbered, where applicable, to reflect this addition.

2. The MODES 3, 4, and 5 Applicability of ITS 3.3.8.3, "RPS Electric Power Monitoring — Scram Solenoids," as it relates to control rod withdrawal, is revised to not include MODES 3 and 4, consistent with the Applicability of RPS Functions in ITS 3.3.1.1. In MODES 3 and 4, a control rod can only be withdrawn from a core cell containing one or more fuel assemblies in accordance with ITS 3.10.3, "Single Control Rod Withdrawal — Hot Shutdown" and ITS 3.10.4, "Single Control Rod Withdrawal — Cold Shutdown," respectively. Therefore, ITS 3.10.3 and ITS 3.10.4 includes OPERABILITY requirements for RPS Functions and control rods (ITS 3.9.5). As a result, ITS 3.10.3 and ITS 3.10.4 has been modified to also include requirements for the RPS Electric Power Monitoring — Scram Solenoids to be OPERABLE when the RPS Functions and control rods are required to be OPERABLE. In addition, ISTS 3.3.8.2 Required Action C.2 has been deleted since ITS 3.3.8.3 is not required to be applicable in MODE 3, ISTS 3.3.8.2 Required Actions D.2.1 and D.2.2 have been deleted since RHR isolation instrumentation is not supplied by the RPS scram solenoid bus, and the Note to ITS SR 3.3.8.3.1 has been modified to reflect changes to the Applicability.

3. The brackets have been removed and the proper plant specific information/value has been provided.

4. The proper NMP2 plant specific nomenclature/value/design requirements have been provided.

5. A Note has been added to the Surveillance Requirements for ITS 3.3.8.3 to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances provided the other RPS electric power monitoring assembly for the associated RPS scram solenoid bus is OPERABLE. The 6 hour testing allowance has been granted by the NRC in Technical Specification amendments for Georgia Power Company's Hatch Unit 1 (amendment 185) and Unit 2 (amendment 125) and Washington Public Power Supply System Unit 2 (amendment 149, the ITS amendment). The NRC has also granted this allowance in other topical reports for the RPS, ECCS, and isolation instrumentation.

6. The Note to ISTS SR 3.3.8.2.1 (ITS SR 3.3.8.3.1) has been deleted since the design of the NMP2 RPS scram solenoid bus electric power monitoring assemblies allows their testing without de-energizing the RPS scram solenoid bus. This design was implemented during the last refueling outage and the deletion is consistent with a recent license amendment change (Amendment 86 issued March 18, 1999). A

2 INSERT SR 3.3.2.1.1

Operating experience has shown that these components usually pass the Surveillance when performed at the 92 day Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

2 INSERT SR 3.3.2.1.4

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 when ≥ 30% RTP, 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). 1C

BASES (continued)

to mitigate any accident or transient (2)

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 is included as required by the NRC Policy Statement. (meets Criterion 4 of Reference 2) (3)

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 (5) (4) within the specified Allowable Value of SR 3.3.4.2.6. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump drive motor breakers. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. (1) (2) (2) (and the LFMG input and output breakers) (fast speed) (C)

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. 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 unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the ATWS analysis. The Allowable Values are derived from the analytic limits corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for. (2) (ATWS) (2) (analog trip module) (2) (by accounting uncertainty) (2) (Ref 3) (2) (Insert ASA)

The individual Functions are required to be OPERABLE in MODE 1 to protect against common mode failures of the

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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 recirculation pump from service in an orderly manner and without challenging plant systems.

breaker(s)

SURVEILLANCE REQUIREMENTS

~~Reviewer's Note: Certain Frequencies are based on approved topical reports. In order for a licensee to use these Frequencies, the licensee must justify the Frequencies as required by the staff SER for the topical report.~~

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. 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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.1 (continued)

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.

SR 3.3.4.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. 1

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. 4

SR 3.3.4.2.3 2 2

2 analog modules

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.2.3. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology. 5 4 1C

2 ATWS

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.3 (continued)

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

Insert SR 3.3.4.2.4

SR 3.3.4.2.6 5 4

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 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis and engineering judgment.

SR 3.3.4.2.5 6 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 18 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 18 24 month Frequency.

(continued)

(4) INSERT SR 3.3.4.2.4

SR 3.3.4.2.4

This SR ensures that the LFMG breaker trip portion of the ATWS-RPT initiated from the Reactor Vessel Steam Dome Pressure — High Function will not be inadvertently bypassed for > 29 seconds when THERMAL POWER is > 5% RTP. This involves verification of the time delay and calibration of the APRM Downscale trip channel. Adequate margins for the instrument setpoint methodologies are incorporated into the actual APRM setpoint. If any time delay or APRM Downscale setpoint is nonconservative (i.e., the Reactor Vessel Steam Dome Pressure — High Function is bypassed for > 29 seconds when THERMAL POWER is > 5% RTP), the affected Reactor Vessel Steam Dome Pressure — High Function is considered inoperable. Alternately, if only the APRM downscale setpoint is nonconservative, the APRM channel can be placed in the conservative condition (e.g., placed in the inop trip condition). If placed in the conservative condition, this SR is met and the associated Reactor Vessel Steam Dome Pressure — High Function is considered OPERABLE.

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the APRM setpoint analysis and is also based on engineering judgement and the reliability of the time delay components.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

All changes are (1) unless otherwise indicated

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 units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) ambient 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) and RCIC/residual heat removal (RHR) steam line flow, (h) ventilation exhaust radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential flow, (l) reactor steam dome pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. The only exception is SLC System initiation. In addition, manual isolation of the logics is provided.

and hac delay relays

Standby Gas Treatment (SGT) System

vessel

the SGT System exhaust radiation sensor.

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

(continued)

All changes are (1) unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(4) 3.e, 3.f, 3.g, 3.h, 3.i. Ambient and Differential Temperature—High

Ambient and Differential Temperatures are provided to detect a leak from the associated system steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Ambient and Differential Temperature—High signals are initiated from thermocouples that are appropriately located to protect the system that is being monitored. Two instruments monitor each area. Six channels for RHR and RCIC Ambient Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two for the RCIC room and four for the RHR area.

There are 12 thermocouples (four for the RCIC room and eight for the RHR area) that provide input to the Area Ventilation 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 six (two for the RCIC room and four for the RHR area) available channels.

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

This Function isolates the Group 6 valves.

INSERT 3.j

(4) 3.g, 3.h. Main Steam Line Tunnel Ambient and Differential Temperature—High

Ambient and Differential Temperature—High is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite limits may be reached. However, credit for these instruments is not taken in any

(continued)

(4)

INSERT 3.j

3.j. Area Temperature — Timer

The RCIC Area Temperature — Timer is provided to ensure RCIC is not isolated if power is lost to the Area Temperature — High Functions control circuits (the control circuits are powered from the RPS logic buses). This Function is not assumed in any USAR transient or accident analysis since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

The Area Temperature — Timer Function delays all Area Temperature — High signals associated with RCIC isolation by use of time delay relays. When an Area Temperature — High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels for Area Temperature — Timer 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 ensure a loss of power to the Area Temperature — High control circuits does not result in an isolation, but not so long as to impact offsite dose calculations.

This Function isolates the Group 10 valves.

All changes are (4) unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.i. Main Steam Line Tunnel Temperature Timer (continued) (4)

sufficient time to isolate all other potential leakage sources in the main steam tunnel before RCIC is isolated.

This Function isolates the Group 4 valves.

(7) (k) 3.j. RCIC/RHR High Steam Line Flow—High (3) (c)

RCIC/RHR high steam line flow is provided to detect a break of the common steam line of RCIC and RHR (steam condensing mode) and initiates closure of the isolation valves for both systems. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. Therefore, the isolation is initiated at high flow to prevent or minimize core damage. Specific credit for this Function is not assumed in any FSAR accident or transient analysis since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC/RHR steam line break from becoming bounding.

(RCK) (1)

The isolation action along with the scram function of RPS ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The RCIC/RHR steam line flow signals are initiated from two differential pressure transmitters that are connected to the steam line. Two channels with one channel in each trip system are available and required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Allowable Value is selected to ensure that the trip occurs to prevent fuel damage and maintains the MSLB as the boundary event. (chosen to be low enough)

(ing) (6)

This Function actuates the Group 6 valves. (10)

3.m. Drywell Pressure—High (4)

High drywell pressure can indicate a break in the RCPB. The RCIC isolation of the turbine exhaust is provided to prevent communication with the drywell when high drywell pressure exists. A potential leakage path exists via the turbine exhaust. The isolation is delayed until the system becomes unavailable for injection (i.e., low steam line pressure). The isolation of the RCIC turbine exhaust by Drywell Pressure—High is indirectly assumed in the FSAR accident analysis because the turbine exhaust leakage path is not assumed to contribute to offsite doses.

(continued)

BASES

All changes are (1) unless otherwise indicated

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.m. Drywell Pressure—High (continued)

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of RCIC Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure—High Allowable Value (LCO 3.3.5.1), since this is indicative of a LOCA inside primary containment.

This Function isolates the Group 9 valves.

(4)

INSERT 3.l (4)

(4) 3.m. Manual Initiation

The Manual Initiation push button channels introduce signals into the RCIC System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific UFSAR 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.

(5) (6) (a) (5) (1) (C)

(when a system initiation signal is present)

There are four push buttons for RCIC. Two manual initiation switch buttons per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

is one

Four channels of RCIC Manual Initiation are available and are required to be OPERABLE.

One (4) (15) (15) (Function)

INSERT 3.M

4. Reactor Water Cleanup System Isolation

4.a. Differential Flow—High

(2) (C)

This Function isolates the outboard Group 10 valve.

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area or differential temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow, is

(continued)

(4) INSERT 3.l 1(c)

3.l RCIC/RHR Steam Flow — Timer

The RCIC/RHR Steam Flow — Timer is provided to prevent false isolations on RCIC/RHR Steam Flow — High during system startup transients and therefore improves system reliability. This Function is not assumed in any USAR transient or 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/RHR Steam Flow — Timer Function delays the RCIC/RHR Steam Flow — High signals by use of time delay relays. When a RCIC/RHR Steam 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/RHR Steam Flow — Timer 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 10 valves.

(5) INSERT 3.m 1(c)

in MODES 1, 2, and 3 since these are the MODES in which the RCIC System Isolation automatic Functions are required to be OPERABLE. As noted (footnote (c) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 10 RCIC isolation valve since the signal only provides input into one of the two trip systems.

BASES

ACTIONS

A.1 (continued)

acceptable (Refs. 5 and 6) 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.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic isolation capability being lost for the associated penetration flow path(s). The MSL isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate a trip signal from the given Function on a valid signal. 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, 2.e, 2.f, 2.g, 3.d, 4.b, 5.a, 5.d, and 5.e, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 3.a, 3.b, 3.c, 3.e, 3.f, 3.g, 3.h, 3.i, 3.j, 3.k, 4.a, 4.b, 4.c, 4.d, 4.g, 4.h, 4.i, 4.j, and 4.k, this would

(continued)

BASES

ACTIONS

B.1 (continued)

require one trip system to have one channel OPERABLE or in trip. For Functions 3.[illegible], 3.[illegible], 4.e, 4.[illegible], 5.a, and 5.[illegible], 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.[illegible], 2.[illegible], 3.[illegible], and 4.[illegible]), 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 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 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). Alternatively, 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

(continued)

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. Alternatively,

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

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

4.16 kV Emergency Bus Undervoltage

1.a. 1.b. 2.a. 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

but after the voltage drops below the maximum Loss of Voltage Function Allowable Value

available, but only two channels of Loss of Voltage - 4.16 kV Basis per 4.16 kV emergency bus is

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, but short enough to ensure that power is available to the required equipment.

Division 1, 2 and 3

Three channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Four channels input to each of the three DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

1.c. 1.d. 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

One channel of Loss of Voltage-Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements

(continued)

(Since a failure of a required loss of voltage channel or time delay channel will only impact the ability of one of the three DGs to start, and only two DGs are credited in the accident analyses, the DG function is still maintained)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 1.e, 2.c, 2.d, 2.e. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

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 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.

Four channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

(continued)

BASES

E.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODES with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

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

In addition, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.2.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2.2). Required Action D.2.1 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.

<INSERT ACTION E.> prev. page

INSERT ACTION F

SURVEILLANCE REQUIREMENTS

<INSERT SR>

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency 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 in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

BASES

ACTIONS

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

In addition, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.2.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2.2). Required Action D.2.1 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.

INSERT SR

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the 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 in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

Insert Page B 3.3-246g

A.1

Specification 3.5.2

EMERGENCY CORE COOLING SYSTEMS

ECCS - SHUTDOWN

SURVEILLANCE REQUIREMENTS

SR3.5.2.3
SR3.5.2.4
SR3.5.2.5
SR3.5.2.6

4.5.2.1 At least the above required ECCS divisions shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1. A.5

SR3.5.2.2.b

4.5.2.2 The HPCS system shall be determine OPERABLE at least once per 12 hours by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2.e. 1 C

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV and each non-PCIV listed in Table 3.6.1.3-1 shall be OPERABLE. 1C

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Only applicable to penetration flow paths with two or more PCIVs. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND	4 hours except for main steam line AND 8 hours for main steam line (continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.12	Verify leakage rate through each MSIV is ≤ 24 scfh when tested at ≥ 40 psig.	In accordance with 10 CFR 50 Appendix J Testing Program Plan
SR 3.6.1.3.13	Verify combined leakage rate through hydrostatically tested lines that penetrate the primary containment is within limits.	In accordance with 10 CFR 50 Appendix J Testing Program Plan

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	Verify each RHR drywell spray subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.1.6.2	Verify, by administrative means, that each required RHR pump is OPERABLE.	92 days
SR 3.6.1.6.3	Verify each drywell spray nozzle is unobstructed.	10 years

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for SCIVs that are open under administrative controls. ---------- Verify each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	31 days
SR 3.6.4.2.2	Verify the isolation time of each power operated, automatic SCIV is within limits.	92 days
SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated automatic isolation signal.	24 months

BASES

BACKGROUND (continued)	DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.1% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 39.75 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. Primary containment air locks satisfy Criterion 3 of Reference 3.
LCO	As part of the primary containment pressure boundary, the air lock safety function is related to control of containment leakage following a DBA. Thus, the air lock structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from primary containment.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the 10 CFR 50 Appendix J Testing Program Plan. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established as a small fraction of the total allowable primary containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Types B and C primary containment leakage rate. 1 C

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs and the non-PCIVs listed in Table 3.6.1.3-1 (2CMS*SOV74A, 74B, 75A, 75B, 76A, 76B, 77A, and 77B), in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs 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. C

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges (which include plugs and caps as listed in Reference 1), and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration, except for penetrations isolated by excess flow check valves, so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system. B

The 12 and 14 inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions. The 12 and 14 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. However, the purge valves may be open when being used for pressure control, inerting, de-inerting, ALARA, or air quality considerations since they are fully qualified.

(continued)

BASES

BACKGROUND (continued)

A two inch bypass line is provided when the primary containment full flow line to the Standby Gas Treatment (SGT) System is isolated.

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV (and non-PCIVs listed in Table 3.6.1.3-1) OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO. 1C

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a loss of coolant accident (LOCA) and a main steam line break (MSLB) (Refs. 2 and 3). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in References 2 and 3, the LOCA is the most limiting event due to radiological consequences. In addition, the non-PCIVs listed in Table 3.6.1.3-1 are also assumed to be closed during the LOCA. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 3 second closure time is assumed in the MSIV closure (the most severe overpressurization transient) analysis (Ref. 4) and 5 second closure time is assumed in the MSLB analysis (Ref. 3). Likewise, it is assumed that the primary containment isolates such that release of fission products to the environment is controlled. 1B 1B 1C 1B

The DBA analysis assumes that isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a, prior to fuel damage.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PCIVs satisfy Criterion 3 of Reference 5. B

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. The valves covered by this LCO are listed with their associated stroke times in Ref. 1. B

The normally closed manual PCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. Normally closed automatic PCIVs, which are required by design (e.g., to meet 10 CFR 50 Appendix R requirements) to be de-activated and closed, are considered OPERABLE when the valve is closed and de-activated. These passive isolation valves and devices are those listed in Reference 1. Purge valves with resilient seals, secondary containment bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing. C B

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents. In addition, the LCO ensures leakage through the non-PCIVs listed in Table 3.6.1.3-1 are within the limits assumed in the accident analysis. C

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be normally closed in MODES 4 and 5. Certain valves are required to be OPERABLE, however, to prevent inadvertent reactor vessel draindown. These valves are

(continued)

BASES

APPLICABILITY (continued)

those whose associated instrumentation is required to be OPERABLE according to LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a

B

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside the primary containment and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside the primary containment the specified time period of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and the existence of other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two or more PCIVs inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. B

Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within 4 hours except for excess flow check valves (EFCVs) and penetrations with a closed system and 72 hours for EFCVs and penetrations with a closed system. The Completion Time of 4 hours for valves other than EFCVs and in penetrations with a closed system is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The 72 hour Completion Time for penetrations with a closed system is reasonable considering the relative stability of the closed system piping or water seal (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Ref. 6. The Completion Time of 72 hours for EFCVs is also reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

B B B B B

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two or more PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV. B

Required Action C.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

With the secondary containment bypass leakage rate (SR 3.6.1.3.11), MSIV leakage rate (SR 3.6.1.3.12), or hydrostatically tested line leakage rate (SR 3.6.1.3.13) not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage rate must be restored to within limit within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two B B B B

(continued)

BASES

ACTIONS

D.1 (continued)

isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function. The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6.

E.1, E.2, and E.3

In the event one or more containment purge exhaust valves are not within the purge valve leakage limits, purge exhaust valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. If a purge exhaust valve with resilient seals is utilized to satisfy Required Action E.1 it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not

(continued)

BASES

ACTIONS

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

require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Required Action E.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low. B B

For the containment purge exhaust valve with resilient seal that is closed in accordance with Required Action E.1, SR 3.6.1.3.6 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge exhaust valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the plant must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending the OPDRVs would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valves to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR verifies that the 12 inch and 14 inch primary containment purge valves are closed as required or, if open, opened for an allowable reason.

The SR is modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided that either: a) the SGT System is OPERABLE (i.e., both subsystems); or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE. These primary containment purge valves are

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The allowance is intended to balance the operational needs of the unit with the requirement to preclude a radiological release through the purge exhaust lines. With the primary containment atmosphere being exhausted through the containment full flow line to the SGT System, a pressure transient could damage the operating SGT subsystem. Thus both subsystems are required to be OPERABLE when the full flow line is in service. This ensures that, if an accident occurs that damages the operating SGT subsystem, the remaining SGT subsystem is still available to perform the intended SGT System safety function. When the full flow line is not in service (i.e., the two inch bypass valve is open), then only one SGT subsystem is required to be OPERABLE since a pressure transient cannot damage the operating SGT subsystem. The 31 day Frequency is consistent with other primary containment isolation valve requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.2 (continued)

controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. 1B

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing. 1B 1B 1B 1C

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open under administrative controls are not required 1B

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, 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 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that each valve will isolate in a time period less than or equal to that assumed in the safety analysis. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J Option B (Ref. 7), is required to ensure OPERABILITY. The primary containment purge supply valves, which are secondary containment bypass leakage pathway valves, are tested at a pressure of 40.0 psig and the primary containment purge exhaust valves, which are not secondary containment bypass leakage pathway valves, are tested at P_a, 39.75 psig. The leakage limit for the 12 inch supply and exhaust valves are 3.75 scfh while the 14 inch

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.6 (continued)

supply and exhaust valve leakage limit is 4.38 scfh. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining these penetrations leak tight (due to the direct path between primary containment and the environment in some cases), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.8

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. 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 this Surveillance when performed at the 24 month Frequency.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.8 (continued)

Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. In addition, this Surveillance shall be performed in MODE 4 or 5. 1C

SR 3.6.1.3.9

This SR requires a demonstration that each EFCV is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This SR provides assurance that the instrumentation line EFCVs will perform as designed. Some hydraulic EFCVs are tested by providing an instrument line break signal with reactor pressure above 600 psig. Testing above this pressure range provides a high degree of assurance that these valves will close during an instrument line break while at normal operating pressure. The remaining hydraulic EFCVs are tested with process fluid or demin water at low pressure. The pneumatic EFCVs are tested by providing an instrument line break signal with pressure at approximately 15 psig to 150 psig. These test pressures are selected to simulate the actual operating conditions the EFCVs are expected to experience during instrument line breaks outside containment.

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 this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired, and shall be installed in

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.10 (continued)

accordance with the manufacturer's recommendations. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths (with the exception of the MSIVs, which are tested per SR 3.6.1.3.12) is less than or equal to the specified leakage rate. While the MSIVs are also classified as secondary containment bypass leakage pathway valves, they are evaluated according to SR 3.6.1.3.12, and if not within limits, actions are required to be taken in accordance with ACTION D. This provides assurance that the assumptions in the radiological evaluations that form the basis of the USAR (Ref. 2) are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan. 1B 1B

Bypass leakage is considered part of L_a.

SR 3.6.1.3.12

The analyses in Reference 1 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 24 scfh when tested at 40 psig. This ensures that MSIV leakage is properly accounted for in determining

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.12 (continued)

the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

MSIV leakage is considered part of L_a.

SR 3.6.1.3.13

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 1 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 1 gpm times the total number of hydrostatically tested PCIVs when tested at $\geq 1.10\ P_a$ (43.73 psig). The combined leakage rates must be demonstrated in accordance with the leakage test Frequency required by the 10 CFR 50 Appendix J Testing Program Plan. C

REFERENCES

1. Technical Requirements Manual.
2. USAR, Section 15.6.5.
3. USAR, Section 15.6.4.
4. USAR, Section 15.2.4.
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section 6.2.4.3.2.
7. 10 CFR 50, Appendix J Option B.

B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell and Suppression Chamber Pressure

BASES

BACKGROUND

The drywell and suppression chamber internal pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

Transient events, which include inadvertent drywell spray initiation, can reduce the drywell and suppression chamber internal pressure. Without an appropriate limit on the minimum drywell and suppression chamber internal pressure (14.2 psia), the design limit for negative containment differential pressure of 4.7 psid could be exceeded (Ref. 1). 1C 1C 1C

The limitation on the maximum drywell and suppression chamber internal pressure (15.45 psia) provides added assurance that the peak LOCA drywell and suppression chamber pressure does not exceed the design value of 45 psig (Ref. 1). 1C

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 2). Among the inputs to the design basis analysis is the initial drywell and suppression chamber internal pressure. The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 45 psig and that peak negative pressure for an inadvertent drywell spray event does not exceed the design value of 4.7 psid.

Drywell and suppression chamber pressure satisfies Criterion 2 of Reference 3.

LCO

A limitation on the drywell and suppression chamber internal pressure of ≥ 14.2 psia and ≤ 15.45 psia is required to ensure that primary containment initial conditions are consistent with the initial safety analyses assumptions so that containment pressures remain within design values during a LOCA and the design value of containment negative pressure is not exceeded during an inadvertent operation of drywell sprays.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.1.6.2

Verifying, by administrative means, that each required RHR pump is OPERABLE ensures that the RHR pump is capable of performing its intended function (i.e., capable of developing the assumed drywell spray flow rate) when in the drywell spray mode. This Surveillance is met by verifying that another required Surveillance, which demonstrated the RHR pump OPERABILITY, was performed within the required Frequency. The verification can be performed by examining logs or other information, to determine if a required RHR pump is out of service for maintenance or other reasons. It is not necessary to perform an additional Surveillance needed to demonstrate the OPERABILITY of the required RHR pumps. The Frequency of 92 days is consistent with the normal RHR pump flow rate Surveillance Frequency ("in accordance with the Inservice Testing Program") in other Surveillances. C

SR 3.6.1.6.3

This Surveillance is performed every 10 years to verify by performance of an air flow test that the spray nozzles in the drywell spray spargers are not obstructed and that flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Section 6.2.5.2.1.
3. 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES (continued)

temperature of 120°F are assumed for the Reference 2 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of Reference 4.

LCO

A limitation on the suppression pool average temperature is required to assure that the primary containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows:

a. Average temperature ≤ 90°F with THERMAL POWER > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 105°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 90°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 90°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ 110°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the plant will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

At 1% RTP, heat input is approximately equal to normal system heat losses.

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(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power limit, the initial conditions exceed the conditions assumed for the Reference 1 and 2 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > 90°F, increased monitoring of the pool temperature is required to ensure it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 90°F with THERMAL POWER > 1% RTP when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, the testing must be immediately suspended to preserve the pool heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 within 36 hours is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when pool temperature is > 110°F, increased monitoring of pool temperature is required to ensure that it remains ≤ 120°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours and the plant must be brought to 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 without challenging plant systems.

Continued addition of heat to the suppression pool with pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

temperature or pressure. Furthermore, if a blowdown were to occur when temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of at least one OPERABLE post accident monitoring instrumentation channel in each suppression pool quadrant. Alternatively, average temperature can be determined by taking an arithmetic average of 10 OPERABLE suppression pool water temperature channels, which are distributed in different suppression pool sectors. There is no divisional requirement with respect to the instrument channels for this SR. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Appendix 6A.10.1.
3. NUREG-0783.
4. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of

(continued)

BASES

ACTIONS

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

reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. C

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases, a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times; i.e., all inner doors closed or all outer doors closed. Thus, each access opening has one door closed. However all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being B B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.3 (continued)

performed on an access opening. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator. (B)

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 2670 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that the secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds with the initial secondary containment pressure ≥ 0 psig, using one SGT subsystem. SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm. This flow rate is the assumed secondary containment leak rate during the drawdown period. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The drawdown test conditions must be adjusted based on the methodology in Reference 5 to compensate for actual inleakage flow and initial conditions during the test. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of (C) (C) (C) (C)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 3.6A.2.1.5.
2. USAR, Section 15.6.5.
3. USAR, Section 15.7.4.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 6.2.3.4.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of Reference 4.

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3.

The normally closed manual SCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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, D.2, and D.3

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated 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.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. C C

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position. C

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

added assurance that the SCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing. C

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low. B

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.3 (continued)

Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance 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.

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. Technical Requirements Manual. B
4. 10 CFR 50.36(c)(2)(ii). B

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1, E.2, and E.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating (from the control room using the manual initiation switch) each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system. (B)

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 6). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance 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 (continued)

SR 3.6.4.3.4

This SR requires verification that the SGT decay heat removal air inlet valves can be opened. This ensures that the decay heat removal mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance 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.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.5.1.2.2.
3. USAR, Section 15.6.5.
4. USAR, Section 15.7.4.
5. 10 CFR 50.36(c)(2)(ii).
6. Regulatory Guide 1.52, Rev. 2.

A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT ISOLATION VALVES

SURVEILLANCE REQUIREMENTS

L.6

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

LA.5 LD.1 C

SR 3.6.1.3.8 4.6.3.2 Each primary containment automatic isolation valve shall be demonstrated OPERABLE during COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

24 or actual LB A.1

SR 3.6.1.3.5 4.6.3.3 The isolation time of each primary containment power operated or automatic valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

isolation LA.1

SR 3.6.1.3.9 4.6.3.4 Each reactor instrumentation line excess flow check valve shall be demonstrated OPERABLE at least once per 18 months by verifying that the valve checks flow.

LD.1 24 L.9

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

LD.1

SR 3.6.1.3.4 a. At least once per 31 days by verifying the continuity of the explosive charge.

24

SR 3.6.1.3.10 b. At least once per 18 months by removing at least one explosive squib from at least one explosive valve, such that each explosive squib in each explosive valve will be tested at least once per 36 months, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and operating life, as applicable.

definition of STAGGERED TEST BASIS

48 LD.1

LA.2

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A.1

Specification 3.6.1.3

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than La, 1.1% by weight of the containment air every 24 hours at Pa, 39.75 psig.

b. A combined leakage rate on a minimum pathway basis of less than 0.60 La for all penetrations and all Primary Containment Isolation Valves, except for main steam line isolation valves* (and Primary Containment Isolation Valves which are hydrostatically leak tested), subject to Type B and C tests when pressurized to Pa, 39.75 psig.

c. A combined leakage rate of less than or equal to 1 gpm times the total number of containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 Pa, 43.73 psig.

SR 3.6.1.3.13
LCO 3.6.1.3
SR 3.6.1.3.1

within limits

LA.4

C

d. Less than or equal to that specified in Table 3.6.1.2-1 through valves in lines that are potential bypass leakage pathways when tested at 40.0 psig.

SR 3.6.1.3.11
SR 3.6.1.3.12

LA.3 purge valves only

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate equaling or exceeding 1.0 La or

See Discussion of Changes for ITS: 3.6.1.1, in this section.

* Exemption to Appendix J of 10 CFR 50

A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 (Continued)

ACTION:

b. The measured combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steam line isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests equaling or exceeding 0.60 La, or

CONDITION D

c. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, or

limits — LA.4

C

CONDITION D/E

d. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1

LA.3 purge valves only

Restore:

a. The overall integrated leakage rate to less than 1.0 La, and

b. The combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steamline isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests to less than 0.60 La, and

Required Action D.1

c. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves, and

within limits — LA.4

C

Required Actions D.1 and E.1

d. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 for any valve that is part of a potential bypass leakage path.

LA.3 purge valves only

L.12

extend Completion times from 1 hour to 4 hours for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage, 8 hours for MSIV leakage, and 72 hours for hydrostatically tested line leakage on a closed system

B

* Exemption to Appendix J to 10 CFR 50

see Discussion of Changes for ITS: 3.6.1.1, in this section.

A.1

Specification 3.6.1.3

PROCEDURE AND PROGRAMS

PROGRAMS

6.8.4.f (Continued)

Leakage Rate acceptance criteria are:

1. Primary Containment leakage rate testing acceptance criterion is less than 1.0 La. The combined leakage rate for Type B and C tests on a minimum pathway basis, except for main steam line isolation valves* and Primary Containment isolation valves which are hydrostatically tested, is less than 0.6 La.

   During the first unit startup following testing in accordance with this program, the as-left leakage rate acceptance criteria are less than 0.6 La for the Type B and C tests on a maximum pathway basis, except for main steam line isolation valves* and Primary Containment isolation valves which are hydrostatically tested, and less than or equal to 0.75 La for Type A tests;

2. Air lock testing acceptance criteria are:

   a. Overall air lock leakage rate is less than or equal to 0.05 La when tested at greater than or equal to Pa,

   b. For each door, leakage rate is less than or equal to 5 scfh when the gap between the door seals is pressurized to greater than or equal to 10 psig.

SR3.6.1.3.13 3. Hydrostatic testing acceptance criterion is a combined leakage rate of less than or equal to 1 gpm times the total number of containment isolation valves in hydrostatically tested lines which penetrate primary containment, when tested at 1.10 Pa, 43.93 psig. (LA4) (within limits) (a)

The provisions of SR 4.0.2 do not apply to the test frequencies specified in the 10 CFR 50 Appendix J Testing Program Plan.

The provisions of SR 4.0.3 are applicable to the 10 CFR 50 Appendix J Testing Program Plan.

(see Discussion of Changes for ITS: 5.5, "Programs and Manuals," in Section 5.5.)

* Exemption to Appendix J to 10 CFR 50

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.3 The allowable leak rates through resilient seal purge valves in potential bypass leakage paths identified in CTS Table 3.6.1.2-1 and CTS 4.6.1.7.2 and the leak rate test pressures in CTS 3.6.1.2.d, CTS 3.6.1.2 Action d, 4.6.1.2.2, and 4.6.1.7.2 are proposed to be relocated to the Bases. The listing of valves, associated leakage limits, and test pressure are related to design and are not necessary for ensuring the test is performed. The requirements of CTS 3.6.1.2.d, 4.6.1.2.2 and 4.6.1.7.2 have been maintained in proposed SR 3.6.1.3.6, which ensures the proper tests are performed for the primary containment purge valves with resilient seals. This formatting change has been made in accordance with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.4 Requirements in CTS LCO 3.6.1.2.c, 3.6.1.2 Action c (including the Restore portion of the Action), and 6.8.4.f.3 concerning the leakage limit and test pressure for valves in hydrostatically tested lines are proposed to be relocated to the Bases. The leakage limits and test pressure are not necessary for ensuring the test is performed. The requirements of ITS 3.6.1.3 and SR 3.6.1.3.13 are adequate to ensure the OPERABILITY of these valves and that they are tested properly. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS. C

LA.5 The requirement to perform CTS 4.6.3.2 during COLD SHUTDOWN or REFUELING has been relocated to the Bases in the form of a statement that the Surveillance shall be performed in MODE 4 or 5. The proposed Surveillance (for a functional test of each primary containment isolation valve) does not include the restriction on plant conditions. Some isolation valves could be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing safe plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance. Therefore, the relocated requirement is not required to be in the ITS to provide C

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.5 (cont'd) adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS. C

LD.1 The Frequencies for performing CTS 4.6.3.2, 4.6.3.4, 4.6.3.5.b, and 4.3.7.7.c have been extended from 18 months to 24 months in proposed SRs 3.6.1.3.8, 3.6.1.3.9, and 3.6.1.3.10 to facilitate a change to the NMP2 refuel cycle from 18 months to 24 months. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (36 month for CTS 4.6.3.5.b) (i.e., a maximum of 22.5 months (45 months for CTS 4.6.3.5.b) accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (48 months for SR 3.6.1.3.10) (i.e., a maximum of 30 months (60 months for SR 3.6.1.3.10) accounting for the allowable grace period specified in CTS 4.0.2 and proposed Specification 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies (48 month for SR 3.6.1.3.10), if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months or 60 months, as applicable) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 CTS 3.6.3 Action a requires an inoperable PCIV to be restored or the affected penetration isolated in 4 hours. CTS 3.4.7 Action a also requires an inoperable MSIV (which is a PCIV) to be restored or the affected penetration isolated in 4 hours. ITS 3.6.1.3 Required Action A.1 allows 8 hours to isolate the affected penetration when an MSIV is inoperable, and ITS Required Action C.1 (second Completion Time) allows 72 hours to isolate the affected penetration when a PCIV is inoperable in a penetration with a closed system and only one PCIV. For the MSIVs, the additional 4 hours provides more time to restore the inoperable MSIV given the fact that MSIV closure will result in isolation of the affected main steam line and potential for a plant shutdown. The additional time is reasonable since the penetration can still be isolated using the other MSIV and the low probability of a main steam line break. For PCIVs in a penetration with a closed system and only one PCIV, they are either in a closed B B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) system, as specifically defined in NUREG-0800 (the Standard Review Plan), section 6.2.4, or they are in a penetration whose system piping communicates with the suppression pool and is expected to remain submerged during the accident (i.e., a closed system as defined in the USAR). The NRC has allowed this design for NMP2 and other BWRs and, while the reason these types of penetrations meet the requirements of the General Design Criteria (GDC) is not specifically described in the Standard Review Plan, they meet the GDC requirements for being classified as a closed system outside the containment because they satisfy "other defined bases" established by the NRC to meet the GDC requirements. The additional time is reasonable for the closed system valves since the intact piping or the water seal acts as the penetration isolation barrier and ensures that the primary containment boundary is maintained intact until another barrier can be established to isolate the penetration. This additional time also avoids the potential for a plant shutdown and provides time to repair the inoperable PCIV in lieu of isolating the penetration (which could result in an inoperable ECCS subsystem, since the water sealed PCIVs are only in ECCS penetrations). B

L.2 CTS 3.6.3 Action a, CTS 3.4.7 Action a, and CTS 4.6.1.1.b list some, but not all, of the possible acceptable isolation devices that may be used to satisfy the need to isolate a penetration with an inoperable isolation valve. ITS 3.6.1.3 ACTIONS provide a complete list of acceptable isolation devices. Since the result of the ACTIONS continues to be an acceptably isolated penetration for continued operation, the proposed change does not adversely affect safe operation. Many penetrations are designed with check valves as acceptable isolation barriers. With forward flow in the line secured, a check valve is essentially equivalent to a closed manual valve. For those penetrations designed with check valves as acceptable isolation devices, the ITS provides an equivalent level of safety. For penetrations not designed with check valves for isolation, the ITS does not affect the requirements to isolate with a closed deactivated automatic valve, closed manual valve, or blind flange. ITS ACTIONS allowing closed manual valves or check valves with flow secured also apply to isolating main steam lines, even though the design does not provide for these type of isolation devices. This change is simply a result of simplicity in providing a consistent presentation for all penetrations. While this apparent flexibility does not result in any actual technical change in the Technical Specifications, it is listed here for completeness.

L.3 In the event two or more valves in a penetration are inoperable, CTS 3.6.3 Action a, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown would be required. ITS 3.6.1.3 ACTION B provides 1 hour prior to commencing a required shutdown. This proposed 1 hour period is consistent with the existing time allowed for

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various primary containment degradations. This change to CTS 3.6.3 is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which continued operation is allowed and the capability to isolate a primary containment penetration is lost.

L.4 CTS 3.6.3 Action b allows 4 hours to either repair the inoperable excess flow check valve or isolate the associated instrument. ITS 3.6.1.3 Required Action C.1 has extended this time to 72 hours. In this event, a limiting event would still be assumed to be within the bounds of the safety analysis (the excess flow lines contain orifices and are approximately ¼ inch in diameter.) Allowing an extended restoration time, to potentially avoid a plant transient caused by the forced shutdown, is reasonable based on the probability of a EFCV line break event and does not represent a significant decrease in safety. (B)

L.5 An allowance is proposed for intermittently opening, under administrative control, closed primary containment isolation valves, other than those currently allowed to be opened using CTS 3.6.3 LCO Footnote ** and Action Footnote *. The allowance is presented in ITS 3.6.1.3 ACTIONS Note 1, and in Note 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3. Opening of primary containment penetrations on an intermittent basis is required for performing surveillances, repairs, routine evolutions, etc. Intermittently opening closed PCIVs is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the PCIV is open and the administrative controls established to ensure the affected penetration can be isolated when a need for primary containment isolation is indicated.

L.6 CTS 4.6.3.1 is proposed to be deleted. Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, ITS SR 3.0.1 requires the appropriate SRs (in this case SR 3.6.1.3.5 and SR 3.6.1.3.7, as applicable) to be performed to demonstrate OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications.

L.7 Not used. (C)

L.8 The phrase "actual or," in reference to the isolation test signal in CTS 4.6.3.2, has been added to proposed SR 3.6.1.3.8, which verifies that each PCIV actuates on an automatic isolation signal. This allows satisfactory automatic

TECHNICAL CHANGES - LESS RESTRICTIVE

L.8 (cont'd) PCIV isolations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. Operability is adequately demonstrated in either case since the PCIV itself cannot discriminate between "actual" or "test" signals.

L.9 The requirement in CTS 4.6.3.4 that each excess flow check valve must check flow has been deleted. Proposed SR 3.6.1.3.9 now requires the EFCVs to actuate to their isolation position (i.e., closed) on an actual or simulated instrument line break signal. The requirements for the EFCVs are provided in 10 CFR 50 Appendix A, GDCs 55 and 56, and as further detailed in Regulatory Guide 1.11. These requirements state that there should be a high degree of assurance that the EFCVs will close or be closed if the instrument line outside containment is lost during normal reactor operation, or under accident conditions. The Instrument Line Break Analysis in the NMP2 USAR Section 15.6.2 assumes both the EFCV and the manual block valve to be unavailable, i.e., fail to close; the accident is terminated by cooling down the plant. Therefore, since the actual leakage is not an assumption of the accident analysis (the leakage is assumed to be the maximum allowed through the broken line), the leakage limit (i.e., check flow) has been deleted.

L.10 The requirements of CTS 4.6.1.1.b, including footnote b, related to verification of the position of primary containment isolation manual valves and blind flanges, are revised in proposed SR 3.6.1.3.2 and SR 3.6.1.3.3 to exclude verification of manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position. The purpose of CTS 4.6.1.1.b is to ensure that manual primary containment isolation devices that may be misaligned are in the correct position to help ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design and analysis limits. For manual valves or blind flanges that are locked, sealed, or otherwise secured in the correct position, the potential of these devices to be inadvertently misaligned is low. In addition, manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position are verified to be in the correct position prior to locking, sealing, or securing. As a result of this control of the position of these manual primary containment isolation devices, the periodic Surveillance of these devices in CTS 4.6.1.1.b is not required to help ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is maintained within design and analysis limits. This change also provides the benefit of reduced radiation exposure to plant personnel through the elimination of the requirement to check the position of manual valves and blind flanges, located in radiation areas, that are locked, sealed, or otherwise secured in the correct position.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.11 CTS 4.6.1.1.b requires verification that certain primary containment penetrations are isolated. An allowance is proposed to allow the verification of the isolation devices used to isolate the penetrations in high radiation areas to be verified by use of administrative means. The allowance is presented in Note 1 to ITS Required Actions A.2 and C.2, SR 3.6.1.3.2, and SR 3.6.1.3.3. This allowance is considered acceptable since access to these areas is typically restricted in MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment once they have been verified to be in the proper position is low. If for some reason these devices are opened (e.g., maintenance), the associated procedure or work package would require their closure after the work is completed. The Required Action or Surveillance may be performed by reviewing that no work was performed in the associated radiation area since the isolation device was closed or if work was performed in the area that closure was verified upon completion of the work if the valve was opened. In addition, an allowance is proposed to allow verification of isolation devices that are locked, sealed, or otherwise secured to also be performed using administrative means. The allowance is presented in Note 2 to ITS Required Actions A.2 and C.2. Plant procedures control the operation of locked, sealed, or otherwise secured isolation devices; thus the potential for inadvertent misalignment of these devices after locking, sealing, or otherwise securing is low. In addition, the isolation devices were verified to be in the correct position prior to locking, sealing, or otherwise securing.

L.12 CTS 3.6.1.2 Action (Restore) c and d requires restoration of the leakage to within limits, but does not provide a finite Completion Time. However, since the leakage rate from the valves is considered in the current definition of PRIMARY CONTAINMENT INTEGRITY (CTS Definition 1.31) the restoration time of the CTS 3.6.1.1 Action, 1 hour, is applicable. In addition, if a purge supply valve with resilient seals is the reason the leakage is not within limits, CTS 3.6.1.7 Action b is required to be entered, and provides 24 hours to restore the leakage to within limits (however, since CTS 3.6.1.1 Action is more limiting, it will govern the total time to restore leakage). The times to restore the leakage have been modified in the ITS to be 4 hours for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage paths (which includes purge supply valve leakage), excluding MSIVs (ITS 3.6.1.3 Required Action D.1, 1st and 2nd Completion Times), 8 hours for MSIVs (ITS 3.6.1.3 Required Action D.1, 3rd Completion Time), and 72 hours for valves in hydrostatically tested lines on a closed system (ITS 3.6.1.3 Required Action D.1, 4th Completion Time). In addition, the 4 hour and 8 hour times are consistent with the existing times allowed for other conditions when valves in hydrostatically tested lines, secondary containment, or MSIVs are inoperable. With one of the leakages not within limit, the risk associated with continued operation for a short period of time

TECHNICAL CHANGES - LESS RESTRICTIVE

L.12 (cont'd) could be less than that associated with a plant shutdown, since the change provides more time to restore the leakage to within limits. This change is acceptable due to the low probability of an event that would require the leakage to be within limits during the short time in which continued operation is allowed with leakage outside the limits. In addition, for the hydrostatically tested lines on a closed system, the valves are either in a closed system as specifically defined in NUREG-0800, section 6.2.4, or are water sealed, and would not be expected to leak after the accident (i.e., a closed system as defined in the USAR). ITS 3.6.1.3 ACTIONS Note 4 will also require immediately taking the ACTIONS of ITS 3.6.1.1 (which reduces the time allowed to restore the leakage to within limits to 1 hour) if leakage results in the overall primary containment leakage rate acceptance criteria being exceeded. Therefore, assurance is provided that the currently listed leakage limits will not adversely impact primary containment Operability during the extended time allowed to restore the leakage. B

L.13 The details relating to the Line Description and Termination Region for the potential bypass leakage paths in CTS Table 3.6.1.2-1 are proposed to be deleted. These details are not necessary to ensure the leakage rates through the potential bypass leakage paths are within limits. The requirements of ITS 3.6.1.3 (which require the valves to be Operable), SR 3.6.1.3.11 and SR 3.6.1.3.12 (which requires the leakage rates to be verified within limits), and Table 3.6.1.3-1 (which lists the specific valves and the leakage rate limits) are adequate to ensure the leakage rates are maintained within limits. Therefore, these details have not been included in ITS Table 3.6.1.3-1.

L.14 CTS Table 3.6.1.2-1 footnote * states that for certain valves in potential bypass leakage paths, the leakage through each penetration shall be that of the valve with the highest rate in that penetration. ITS Table 3.6.1.3-1 footnote (a) will allow the leakage through the penetration to be the actual pathway leakage, provided the penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange. The reason for assuming the pathway is maximum pathway leakage is to account for a single failure not closing one of the two valves in the penetration. However, if the penetration is already isolated by one of the methods described above, then a single failure cannot occur. Therefore, it is acceptable to assume the leakage through the penetration is the actual leakage through the valve that is isolating the penetration. If the penetration is isolated by both PCIVs, then the leakage through the penetration is the lesser leakage rate of the two PCIVs. This allowance is provided in the ISTS Bases for the secondary containment bypass leakage ACTION (ITS 3.6.1.3 ACTION D.1 Bases) and the associated Surveillance Requirement (proposed SR 3.6.1.3.11).

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.15 CTS 3.6.1.7 limits the time the 12 inch and 14 inch purge valves can be open to 135 hours per 365 days for PURGING OR VENTING. Footnote * to CTS 3.6.1.7 modifies the restriction to allow the purge valves to be open for an unlimited amount of time for primary containment pressure control, provided 2GTS*AOV101 is closed (which isolates the 20 inch line to the SGT System) and the 2 inch bypass line is the only flow path to the SGT System. The ITS does not include the time limitations, and replaces them with specific criteria for opening. The time limits were based on engineering judgement and/or early plant operating experience, and not based on any analytical requirement. The proposed limits on when the purge valves are permitted to be open, provided in the Note to proposed SR 3.6.1.3.1, will ensure appropriate controls. The Note will continue to allow the purge valves to be open for inerting, deinerting, and pressure control, and will now allow the purge valves to also be open for ALARA or air quality considerations for personnel entry, as well as for Surveillances that require the purge valves to be open. Thus, use of the purge valves will continue to be minimized and limited to safety related reasons. The operating history indicates that these valves are only opened for the specified reasons and for cumulative periods that are generally less than the current allowed cumulative times. In addition, these valves are fully qualified to close in the required time under accident conditions to isolate the affected penetrations.

L.16 The requirement in CTS 3.6.1.7.b and CTS 4.6.1.7.1 to verify the primary containment purge valves with resilient seals are blocked to limit their opening to 60° or 70°, as applicable, has been deleted. The limits on the opening ensure the valves will close during a design basis accident (LOCA) to minimize the radiological consequences to within the limits of 10 CFR 100. These blocking devices are permanently installed devices located on the actuator and will require a design change to increase or decrease the current limits. The NMPC Design Control Process and Maintenance Program will ensure the blocking devices are set properly, and therefore, a requirement in the Technical Specifications is not necessary. These settings are not affected by drift, and therefore, if set properly there is no reason to expect a change in the settings. If maintenance was performed on the valve and the actuator was disassembled, the installation instructions will require the blocking devices settings to be verified.

L.17 The requirement in CTS 3.6.1.7 Action b to restore the leakage rate of the inoperable containment purge valve(s) with resilient seals has been changed to allow the isolation of the affected penetration and to continue operations without a requirement to restore the associated valves (ITS 3.6.1.3 Required Action E.1). The allowance provided must use at least one isolation barrier that cannot be adversely affected by a single failure such as a closed and

TECHNICAL CHANGES - LESS RESTRICTIVE

L.17 (cont'd) de-activated automatic valve closed, manual valve, or blind flange. This ensures that a gross breach of the containment does not exist and is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. This flexibility is provided as long as this isolation is verified every 31 days (ITS 3.6.1.3 Required Action E.2) and the purge valve leak rate test is performed every 92 days if a purge exhaust valve with a resilient seal is used to perform the isolation (ITS 3.6.1.3 Required Action E.3). These actions assure that the penetration will not leak in excess of limits should an accident occur while operating, and this alleviates the need to shutdown the facility. This new flexibility is acceptable since the valve design allows individual leakage testing of each purge valve with resilient seal (design permits imposing a back pressure on the outboard purge valves) so that the containment penetration may be isolated by a qualified valve as close as possible to the containment. If both valves are leaking in excess of the limit, a manual valve or blind flange may be used. In addition, in all cases, the actual leakage from the purge valves is also evaluated in accordance with overall leakage limit as required by ITS 3.6.1.3 ACTIONS Note 4. If the limit is exceeded due to the actual purge valve leakage, ITS 3.6.1.1 ACTION A will require leakage to be restored to within limits within one hour. Therefore, the proposed actions will ensure the actual leakage is within the limits of the safety analysis.

L.18 The surveillance frequency of CTS 4.6.1.7.2 (the leakage rate test of primary containment purge valves with resilient seals) is proposed to be extended from 92 days to 184 days and once within 92 days after opening the valve in proposed SR 3.6.1.3.6. The current 92 day frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened) and since the valves are opened during the operating cycle for containment pressure control and to comply with the Inservice Test Program. The surveillance test history indicates that the valves normally pass the leakage limit a the current 92 day frequency. Since the failure mechanism of the seal is a result of cycling the valve, there is no additional need to perform the test at the current frequency if the valves are not cycled. Therefore, based on the surveillance test history and the failure mechanism of the resilient seals, the proposed change is adequate to ensure leakage is maintained within the limit.

L.19 CTS 3.6.5.3 Action a.1 requires suspension of PURGING and VENTING (except when the containment purge full flow line to the SGT System is isolated as allowed by Footnote **) within 30 minutes when one SGT subsystem is inoperable and CTS 3.6.5.3 Action b.1 requires suspension of PURGING, VENTING, or pressure control (with no time specified to suspend the operations) when both SGT subsystems are inoperable. In the ITS, the Note to proposed SR 3.6.1.3.1, which allows the purge valves to be open under certain

TECHNICAL CHANGES - LESS RESTRICTIVE

L.19 (cont'd) conditions, will include the SGT requirements of CTS 3.6.5.3 Actions a.1 (including Footnote **) and b.1. If the purge valves are open when not allowed by the Note, ITS 3.6.1.3 ACTION B will be required to be entered as the purge valves would be considered inoperable. ACTION B allows 1 hour to isolate the penetration. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various containment degradations. This is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which continued operation is allowed with the SGT System inoperable. In addition, the SGT Specification (CTS 3.6.5.3 and ITS 3.6.4.3) would also be requiring the unit to be shut down when both SGT subsystems are inoperable.

A.1

Specification 3.6.1.6

CONTAINMENT SYSTEMS

DEPRESSURIZATION SYSTEMS

SUPPRESSION POOL AND DRYWELL SPRAY

See Discussion of Changes for ITS: 3.6.2.4, "RHR Suppression Pool Spray," in this Section.

LIMITING CONDITIONS FOR OPERATION

LCO 3.6.1.6 3.6.2.2 The suppression pool and drywell spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

LA.1

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

L.1

ACTION:

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

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

A.2

SURVEILLANCE REQUIREMENTS

See Discussion of Changes for ITS: 3.6.2.4 in this Section.

4.6.2.2 The suppression chamber and drywell spray mode of the RHR system shall be demonstrated OPERABLE:

A.3

SR 3.6.1.6.1 a. At least once per 31 days by verifying that each valve, (manual, power-operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

or can be aligned to the correct position

b. By verifying that each of the required RHR pumps develops a flow of at least 450 gpm on recirculation flow through the RHR heat exchanger and suppression pool spray sparger when tested pursuant to Specification 4.0.5.

LA.2

SR 3.6.1.6.3 c. By performance of an air flow test of the drywell spray nozzles at least once per 10 years and verifying that each spray nozzle is unobstructed.

L.2

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

A.2

add proposed SR 3.6.1.6.2 M.1

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TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Currently, there is no requirement to verify the required RHR pumps are OPERABLE with respect to the drywell spray mode. ITS SR 3.6.1.6.2 has been added, as requested by the NRC, to verify, by administrative means, that each required RHR pump is OPERABLE. Therefore, this change is more restrictive on plant operations. C

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details in the CTS 3.6.2.2 LCO relating to system OPERABILITY (in this case the drywell spray function shall have two "independent" loops, each with pumps and flow path) is proposed to be relocated to the Bases. These details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.2 Details in CTS 4.6.2.2.c of the method for performing the Surveillance to verify the drywell spray nozzles are unobstructed (by performance of an air flow test) are proposed to be relocated to the Bases. These details are not necessary to ensure that the OPERABILITY of the drywell spray mode of RHR is maintained. The requirements of ITS 3.6.1.6 and SR 3.6.1.6.2 are adequate to ensure the drywell spray nozzles are maintained unobstructed and the drywell spray mode of RHR is maintained OPERABLE. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

"Specific"

L.1 CTS 3.6.2.2 requires the drywell spray mode of the RHR System to be capable of recirculating water from the suppression pool through the RHR heat exchangers to the drywell spray spargers. ITS 3.6.1.6 relocates the details of what constitutes an Operable drywell spray subsystem to the Bases (See Discussion of Change LA.1 above). However, the requirement to circulate water through the heat exchangers has not been included. The drywell sprays are required to reduce pressure in the drywell and provide mixing of the atmosphere, not cool the primary containment atmosphere. These functions can

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) be met without cooling the suppression pool water prior to spraying it into the drywell. The analysis for drywell spray does not credit cooling of the suppression pool water to perform the pressure mitigation and atmosphere mixing functions. The suppression pool is still required to be cooled by the suppression pool cooling mode, which is governed by another Technical Specification (CTS 3/4.6.2.3 and ITS 3.6.2.3). In addition, while the analysis for inadvertent drywell spray does credit cooling through the heat exchanger, this is to maximize the effect of the inadvertent spray. If the heat exchangers are not functioning during this event, the consequences of an inadvertent spray event will not be as severe. Therefore, this change is considered acceptable.

L.2 The Frequency for performance of the drywell spray nozzle obstruction Surveillance (CTS 4.6.2.2.c) has been extended from 5 years to 10 years in proposed SR 3.6.1.6.3. This change is justified due the passive design of the nozzles, and has been shown acceptable through industry operating experience. This change does not represent a significant increase in the probability of an accident because obstruction of the RHR drywell spray nozzles is not a precursor to any accident. 1C

A.1

Specification 3.6.4.2

CONTAINMENT SYSTEMS

3/4.6.5 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITIONS FOR OPERATION

3.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

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

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

SURVEILLANCE REQUIREMENTS

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

Required Action A.2 and SR 3.6.4.2.1

b. Verifying at least once per 31 days that:

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

2. At least one door in each access to the secondary containment is closed, except during normal entry and exit.

Required Action A.2 and SR 3.6.4.2.1

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

SR 3.6.4.2.1

Required Action A.2

add proposed Required Action A.2 Note and SR 3.6.4.2.1 Note 1

L.6

add proposed SR 3.6.4.2.1 Note 2

L.1

and not locked, sealed, or otherwise secured

L.7

* When irradiated fuel is being handled in the reactor building and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

C

See Discussion of Changes for ITS: 3.6.4.1, "Secondary Containment," in this section.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) can be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing safe plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

L.5 The phrase "actual or," in reference to the isolation test signal in CTS 4.6.5.2.b, has been added to proposed SR 3.6.4.2.3, which verifies that each SCIV actuates on an automatic isolation signal. This allows satisfactory automatic SCIV isolations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. Operability is adequately demonstrated in either case since the SCIV itself cannot discriminate between "actual" or "test" signals.

L.6 CTS 4.6.5.1.b.3 requires verification that certain secondary containment penetrations are isolated. An allowance is proposed to allow the verification of the isolation devices used to isolate the penetrations in high radiation areas to be verified by use of administrative controls. The allowance is presented in ITS 3.6.4.2 Required Action A.2 Note and SR 3.6.4.2.1 Note 1. This is acceptable since the isolation devices are initially verified to be in the proper position and access to them is restricted during operation due to the high levels of radiation in the area. Therefore, the probability of misalignment of the isolation devices is acceptably small. If for some reason these devices are opened (e.g., maintenance), the associated procedure or work package would require their closure after work is completed. The Required Action or Surveillance may be performed by reviewing that no work was performed in the associated radiation area since the isolation device was closed or if work was performed in that area that the closure was verified upon completion of the work if the valve was opened.

L.7 The requirements of CTS 4.6.5.1.b related to verification of the position of secondary containment isolation manual valves and blind flanges, are revised in proposed SR 3.6.4.2.1 to exclude verification of manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position. The purpose of CTS 4.6.5.1.b is to ensure that manual secondary containment isolation devices that may be misaligned are in the correct position to help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. For manual valves or blind flanges that are locked, sealed, or otherwise secured in the correct position, the potential of these devices to be inadvertently misaligned is low. In addition, manual valves and blind flanges that are

C

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) locked, sealed, or otherwise secured in the correct position are verified to be in the correct position prior to locking, sealing, or securing. As a result of this control of the position of these manual secondary containment isolation devices, the periodic Surveillance of these devices in CTS 4.6.5.1.b is not required to help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. This change also provides the benefit of reduced radiation exposure to plant personnel through the elimination of the requirement to check the position of manual valves and blind flanges, located in radiation areas, that are locked, sealed, or otherwise secured in the correct position. C

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

<CTS>

<LCO 3.6.3>
<LCO 3.4.7>
<LCO 3.6.1.7>

LCO 3.6.1.3 Each PCIV, and each non-PCIV in Table 3.6.1.3-1, shall be OPERABLE. (19) (C)

<Appl 3.6.3>
<Appl 3.4.7>
<Appl 3.6.1.2>
<Appl 3.6.1.7>

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

<3.6.3 Act a.4>
<DOC A.2>
<DOC A.3>
<3.6.3 "*" footnote>
<3.6.3 Act b.2>
<DOC L.5>

NOTES

1. Penetration flow paths (except for 1 inch purge valve penetration flow paths) may be unisolated intermittently under administrative controls. (1)
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria (in MODES 1, 2, and 3). (2)

<3.6.3 Act a>
<3.4.7 Act a.1>
<4.6.1.1.b>
<DOC L.11>
<4.6.1.1 "*#" footnote>
<3.6.1.7 Act a>

(3)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. NOTE: Only applicable to penetration flow paths with two PCIVs. (or more) (17)	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours except for main steam line AND 8 hours for main steam line
One or more penetration flow paths with one PCIV inoperable (except for purge valve or secondary containment bypass leakage not within limit). (due to)	AND	

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
<LCO 3.6.1.2.c> <6.8.4.f.3> SR 3.6.1.3.01 (13) (5) ~~NOTES 1. Only required to be met in MODES 1, 2, and 3.~~ (2) ~~2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1 in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions.~~ (12) Verify combined leakage rate ~~of ¼ gpm times the total number of PCIVs~~ through hydrostatically tested lines that penetrate the primary containment is not exceeded when these isolation valves are tested at ≥ 1.1 P_a. (18) within limits	~~NOTE SR 3.0.2 is not applicable~~ (14) In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions Testing Program Plan
SR 3.6.1.3.12 ~~NOTE Only required to be met in MODES 1, 2, and 3.~~ Verify each [ ] inch primary containment purge valve is blocked to restrict the valve from opening > [50]%.	[18] months

<INSERT TABLE 3.6.3.1-1> (13) (1)

16. (continued)

they must be restored in 4 hours, consistent with other secondary containment bypass leakage path valves. In addition, due to this change, ISTS Required Action E.3 has also been modified to pertain to purge exhaust valves only.

17. The words in ISTS Conditions A and B Notes and the words in ISTS Condition B have been modified to state "two or more" in lieu of "two." Some penetration flow paths at NMP2 have more than two PCIVs. This was required by the NRC for some penetrations whose outside PCIV was not close enough to the primary containment. This change will ensure an LCO 3.0.3 entry is not required for this design and the appropriate actions are taken consistent with a plant with only two PCIVs per penetration flow path. This change is also consistent with proposed TSTF-207, Rev. 3 (It is noted that the BWR/6 ISTS markup provided in TSTF-207, Rev. 3 inadvertently left out the words "or more" in Condition B. The BWR/4 ISTS markup included these words in Condition B.) B

18. The leakage limit and test pressure for ISTS SR 3.6.1.3.11 (ITS SR 3.6.1.3.13) have been deleted from the Technical Specification Surveillance based on an NRC Request for Additional Information comment provided in an NRC letter dated 5/10/99. The leakage limit and test pressure are now located in the ITS Bases. This is also consistent with proposed TSTF-52, Revision 2. C

19. The LCO statement has been modified since not all valves in secondary containment bypass leakage pathways are PCIVs (valves 2CMS*SOV74A, 74B, 75A, 75B, 76A, 76B, 77A, and 77B are not PCIVs). C

(M.1) SR 3.6.1.6.2 Verify, by administrative means, that each required RHR pump is OPERABLE. | 92 days (3)

(CTS)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
(4.6.2.2.a) SR 3.6.1.10.1	~~NOTE~~ ~~RHR containment spray subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below [the RHR cut in permissive pressure in MODE 3] if capable of being manually realigned and not otherwise inoperable.~~ Verify each RHR drywell containment spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days (3) or can be aligned to the correct position
~~SR 3.6.1.7.2~~	~~Verify each RHR pump develops a flow rate of ≥ [5650] gpm on recirculation flow through the associated heat exchanger to the suppression pool.~~	~~[In accordance with the Inservice Testing Program or 92 days]~~ (3)
~~SR 3.6.1.7.3~~	~~Verify each RHR containment spray subsystem automatic valve in the flow path actuates to its correct position on an actual or simulated automatic initiation signal.~~	~~[18] months~~ (3)
(4.6.2.2.c) SR 3.6.1.10.6 (3) (3)	Verify each drywell spray nozzle is unobstructed.	~~At first refueling AND~~ 10 years (4)

(INSERT ITS 3.6.1.7 (BWR/4 ISTS 3.6.1.8)) (5)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.6.1.6 - RHR DRYWELL SPRAY

1. The proper plant specific information/nomenclature/value has been provided.

2. The Specification has been renumbered to reflect the deletion of ISTS 3.6.1.6.

3. The NMP2 design does not include an automatically actuated RHR Drywell Spray System. Therefore, the Note to ISTS SR 3.6.1.7.1 and ISTS SR 3.6.1.7.3 have been deleted. In addition, since the system is manually initiated, the word "automatic" has been deleted and the phrase "or can be aligned to the correct position" has been added to the valve position check Surveillance (ITS SR 3.6.1.6.1), consistent with other manual system valve position checks. ISTS SR 3.6.1.7.2 is not included in the current licensing basis for this Specification. This requirement is tested as part of ITS 3.6.2.3. Therefore this SR has been deleted. However, in its place, as requested by the NRC, is a new SR (ITS SR 3.6.1.6.2) that verifies, by administrative means, that each required RHR pump is OPERABLE. In addition, the remaining Surveillance Requirement has been renumbered due to these changes. C

4. This bracketed requirement has been deleted because it is not applicable to NMP2.

5. A new Specification has been added, ITS 3.6.1.7. This Specification is from the BWR/4 ISTS (NUREG-1433 ISTS 3.6.1.8), since the NMP2 design is similar to the BWR/4 design with regard to the vacuum breakers. Therefore, the BWR/4 Specification is used and any deviations from the BWR/4 ISTS are discussed in the Justification for Deviations for ITS: 3.6.1.7.

<CTS>

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE		FREQUENCY
<4.6.5.1.b> <4.6.5.1.b.3> <DOC L.1> <DOC L.6>	SR 3.6.4.2.1	NOTES 1. Valves and blind flanges in high radiation areas may be verified by use of administrative ~~controls~~ Means. 2. Not required to be met for SCIVs that are open under administrative ~~seals~~ controls.	2
	TSTF-45 not locked, sealed, or otherwise secured and is	Verify each secondary containment isolation manual valve and blind flange ~~that is~~ required to be closed during accident conditions is closed.	31 days C
<4.6.5.2.c>	SR 3.6.4.2.2 TSTF-46	Verify the isolation time of each power operated, ~~and each~~ automatic SCIV is within limits.	[~~In accordance with the Inservice Testing Program or 92 days~~] * 1
<4.6.5.2.b>	SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated automatic isolation signal.	~~{18}~~ months 24 1

BASES

LCO (continued)

sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into ~~and~~ or exit from primary containment. 3

1C

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The ~~ability~~ allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. 3 1B 1B

3

The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit.

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the overall primary containment leakage rate.

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.2 - PRIMARY CONTAINMENT AIR LOCKS

1. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, or analysis description.

2. This bracketed requirement/information has been deleted because it is not applicable to NMPC.

3. Editorial change made for enhanced clarity.

4. The brackets have been removed and the proper plant specific information/value has been provided.

5. Typographical/grammatical error corrected.

6. Changes have been made to reflect those changes made to the Specification.

7. These words have been deleted since the primary containment may need to be entered for reasons related to TS that are not specifically on "equipment." This could include sampling and inspections. The intent has not changed in that it must still be related to TS.

8. The change has been made for consistency with similar phrases in other parts of the Bases. The phrase "Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency" is generally used to describe why a 24 month Frequency is acceptable and in almost all cases, the current Frequency in the CTS is 18 months. For this Surveillance, the CTS Frequency could be as long as 18 months, therefore using these words is consistent with similar phrases in other parts of the Bases. B C

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

and the NON-PCIVs listed in Table 3.6.1.3-1 (2CMS*SOV74A, 74B, 75A, 75B, 76A, 76B, 77A, and 77B)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

(which include plugs and caps as listed in Reference 1)

except for penetrations isolated by excess flow check valves,

The 18 and 20 inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions. The 18 and 20 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness. The purge valves must be closed when not being used for pressure control, ALARA, or air quality considerations so ensure that the primary containment boundary assumed in the safety analysis will be maintained.

the primary containment boundary is maintained

However, open may inerting, de-inerting,

since they are fully qualified.

A two inch bypass line is provided when the primary containment full flow line to the Standby Gas Treatment (SGT) System is isolated.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCIV LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a loss of coolant accident (LOCA), a main steam line break (MSLB), and a fuel handling accident inside primary containment (Refs. 2 and 3). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in Reference 3, the MSLB is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 5 second closure time is assumed in the analysis. The safety analyses assume that the purge valves are closed at event initiation. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that within 60 seconds after the accident, isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a. The primary containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

[The purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3. In this case, the single failure criterion remains applicable to the primary containment purge valve due to failure in the control circuit associated with each valve. Again, the primary containment purge valve design precludes a single failure from compromising the primary containment boundary as long as the system is operated in accordance with this LCO.]

PCIVs satisfy Criterion 3 of ~~the NRC Policy Statement~~ Reference 5.

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. ~~Primary containment purge valves that are not qualified to close under accident conditions must be sealed closed [or blocked to prevent full opening] to be OPERABLE.~~ The valves covered by this LCO are listed with their associated stroke times in ~~the FSAR~~ ~~Ref. 2~~.

The normally closed PCIVs are considered OPERABLE when ~~manual~~ valves are closed or open ~~in accordance with administrative controls~~, automatic valves are ~~de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact.~~ These passive isolation valves and devices are those listed in Reference 3. Purge valves with resilient seals, secondary bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

normally closed automatic PCIVs, which are required by design (e.g., to meet 10 CFR 50 Appendix R requirements) to be de-activated and closed are considered OPERABLE when the valve is closed and de-activated.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

In addition, the LCO ensures leakage through the non-PCIVs listed in Table 3.6.1.3-1 are within the limits assumed in the accident analysis.

TSTF-45 This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.[illegible] (continued)

containment, and capable of being mispositioned, are in the correct position. Since verification of valve position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open.

These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.[illegible]

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment, drywell, or steam tunnel, and not locked, sealed, or otherwise secured and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, drywell, or steam tunnel, the Frequency of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low.

if primary containment was deinerted while in MODE 4

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open

the primary containment is inerted and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.6.1.3.6 (continued)~~

~~(e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.~~

7

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. The Frequency of this SR is ~~in accordance with the~~ Inservice Testing Program ~~or 18 months~~.

1

and transient

3

SR 3.6.1.3.8

12

LCO 3.3.6.1, "Primary Containment Isolation Instrumentation,"

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in ~~SR 3.3.6.1.8~~ overlaps this SR to provide complete testing of the safety function. The ~~18~~ month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the ~~18~~ month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24

1

24

7 INSERT SR 3.6.1.3.9

INSERT SR 3.6.1.3.10

SR 3.6.1.3.9 11 7

(with the exception of the MSIVs, which are tested per SR 3.6.1.3.12)

3

or equal to 3

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations ~~of Reference 6~~ are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of

that form the basis of the USAR (Ref 2)

3

In addition, this Surveillance shall be performed in MODE 4 or 5.

1

14

INSERT SR 3.6.1.3.11

3

11

TSTF-30 change not shown

13

C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.8 (continued)

the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J maximum pathway leakage limits are to be quantified in accordance with Appendix J). The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions (and therefore, the Frequency extensions of SR 3.0.2 may not be applied), since the testing is an Appendix J, Type C test. This SR simply imposes additional acceptance criteria.

Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

(Bypass leakage is considered part of L_a. ~~(Reviewer's Note: Unless specifically exempted).~~)

SR 3.6.1.3.10

The analyses in References 2 and 3 are based on leakage that is less than the specified leakage rate. Leakage through all four MSIVs must be ≤ (208) scfh when tested at (P_a) (31.5) psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference 4, as modified by approved exemptions. Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 4), as modified by approved

(continued)

BASES

SURVEILLANCE REQUIREMENTS

The acceptance criteria for the combined leakage of all hydrostatically tested lines is 1gpm times the total number of hydrostatically tested PCIVs when tested at ≥ 1.10 Pa (43.73 psig).

SR 3.6.1.3.10 (continued)

exemptions; thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of References 2 and 3 are met. The combined leakage rates must be demonstrated ~~to be~~ in accordance with the leakage test frequency of Reference 4, as modified by approved exemptions; thus SR 3.0.2 (which allows Frequency extensions) does not apply.

TSTF-30 changes not shown

required by the 10CFR50 Appendix J Testing Program Plan.

[This SR is modified by a Note that states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.]

SR 3.6.1.3.12

Reviewer's Note: This SR is only required for those plants with purge valves with resilient seals allowed to be open during [MODE 1, 2, or 3] and having blocking devices on the valves that are not permanently installed.

Verifying that each [ ] inch primary containment purge valve is blocked to restrict opening to ≤ [50%] is required to ensure that the valves can close under DBA conditions within the time limits assumed in the analyses of References 2 and 3.

The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization

(continued)

13. This change was approved to be made in NUREG-1434, Rev. 1 per change package BWR-15, C.4, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Rev. 1.

14. Editorial change made for enhanced clarity.

15. Changes have been made to be consistent with the Specification. These changes are also consistent with proposed TSTF-207, Rev. 3 and proposed TSTF-30, Rev. 3, except where plant specific differences apply or where typographical/consistency errors are noted. B

16. The discussion in the LCO section about closed valves is modified. This editorial preference is based on an incomplete and misleading discussion of the valves. This change does not modify the requirements or the interpretation of the requirements. B

17. The leakage limit and test pressure for ISTS SR 3.6.1.3.11 (ITS SR 3.6.1.3.13) have been deleted from the Technical Specification Surveillance and moved to the ITS Bases based on an NRC Request for Additional Information comment provided in an NRC letter dated 5/10/99. This is also consistent with proposed TSTF-52, Revision 2. C

18. These words have been deleted since it is unclear as to their meaning. There are other SRs, specifically SR 3.6.1.3.6, SR 3.6.1.3.12, and SR 3.6.1.3.13, that require leakage testing, and these leakage tests have acceptance criteria that are not required by 10 CFR 50 Appendix B. However, these SRs do not have similar statements in the Bases. In addition, the words do not appear to add any necessary information concerning the Surveillance Requirement (i.e., the deletion of the words does not modify the technical requirements of the SR). Therefore, to preclude confusion, the statement that SR 3.6.1.3.11 simply imposes additional acceptance criteria is being deleted. C

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 ~~Primary Containment~~ Pressure

Drywell and Suppression Chamber

BASES

BACKGROUND

The ~~primary containment~~ pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

drywell and suppression chamber internal

~~The limits on primary containment [to secondary containment differential] pressure have been developed based on operating experience. The auxiliary building, which is part of the secondary containment, completely surrounds the lower portion of the primary containment. Therefore, the primary containment design external differential pressure, and consequently the Specification limit, are established relative to the auxiliary building pressure. The auxiliary building pressure is kept slightly negative relative to the atmospheric pressure to prevent leakage to the atmosphere.~~

drywell

Transient events, which include inadvertent ~~containment~~ spray initiation, can reduce the ~~primary containment~~ pressure (~~Ref. 1~~). Without an appropriate limit on the ~~negative containment~~ pressure, the design limit for negative ~~internal~~ pressure of ~~[3.0]~~ psid could be exceeded. ~~Therefore, the Specification pressure limits of [-0.1 and 1.0 psid] were established (Ref. 2).~~

minimum

drywell and suppression chamber internal

containment differential

(14.7 psia)

(Ref. 1)

4.7

maximum drywell and suppression chamber internal

~~The limitation on the primary (to secondary containment differential) pressure provides added assurance that the peak LOCA primary containment pressure does not exceed the design value of 15 psig (Ref. 1).~~

(15.45 psia)

drywell and suppression chamber

45

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 3). Among the inputs to the design basis analysis is the initial ~~primary containment~~ internal pressure. ~~The primary containment [to secondary containment differential] pressure can affect the initial containment internal pressure.~~ The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 15 psig and that peak negative pressure for an inadvertent

45

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.4 - DRYWELL AND SUPPRESSION CHAMBER PRESSURE

1. Changes have been made to reflect the changes made to the Specification.

2. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, or analysis description.

3. The brackets have been removed and the proper plant specific information/value has been provided.

4. The last sentence in the third paragraph of the Background Section is describing both the upper and lower pressure limit, but it follows the description of the lower limit and comes before the description of the upper limit. For clarity, the lower limit value is identified in the description of the lower limit and the upper limit value is identified in the description of the upper limit. In addition, the statement specifies a Reference that is different than the Reference provided for the descriptions of the upper and lower limits. At NMP2, the Reference for the actual limits are the same as the Reference for the descriptions of the limits. Therefore, the single NMP2 Reference is identified at the end of each of the limit descriptions (lower limit and upper limit). C

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

A Note has been added to this SR that allows RHR containment spray subsystems to be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below [the RHR cut in permissive pressure in MODE 3], if capable of being manually realigned and not otherwise inoperable. At these low pressures and decay heat levels (the reactor is shut down in MODE 3), a reduced complement of subsystems can provide the required containment pressure mitigation function thereby allowing operation of an RHR shutdown cooling loop when necessary.

INSERT SR 3.6.1.6.2

SR 3.6.1.7.2

Verifying each RHR pump develops a flow rate ≥ [5650] gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. [The Frequency of this SR is in accordance with the Inservice Testing Program or 92 days.]

SR 3.6.1.7.3

This SR verifies that each RHR containment spray subsystem automatic valve actuates to its correct position upon receipt of an actual or simulated automatic actuation signal. Actual spray initiation is not required to meet this SR. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.6 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at

(continued)

1

INSERT SR 3.6.1.6.2

SR 3.6.1.6.2

Verifying, by administrative means, that each required RHR pump is OPERABLE ensures that the RHR pump is capable of performing its intended function (i.e., capable of developing the assumed drywell spray flow rate) when in the drywell spray mode. This Surveillance is met by verifying that another required Surveillance, which demonstrated the RHR pump OPERABILITY, was performed within the required Frequency. The verification can be performed by examining logs or other information, to determine if a required RHR pump is out of service for maintenance or other reasons. It is not necessary to perform an additional Surveillance needed to demonstrate the OPERABILITY of the required RHR pumps. The Frequency of 92 days is consistent with the normal RHR pump flow rate Surveillance Frequency ("in accordance with the Inservice Testing Program") in other Surveillances.

C

Drywell

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.3 (continued)

the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.7.4

This Surveillance is performed every 10 years to verify that the spray nozzles are not obstructed and that flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

in the drywell spray spargers

by performance of an air flow test

REFERENCES

1. USAR, Section [6.2.1.1.3].
2. ASME, Boiler and Pressure Vessel Code, Section XI.

2. USAR, Section 6.2.5.2.1.
3. 10 CFR 50.36 (c)(2)(ii).

INSERT ITS B3.6.1.7 (BWR/4 ISTS B3.6.1.8)

BASES

LCO (continued)

selected to provide margin below the {110}°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ {95}°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > {95}°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ {110}°F when all OPERABLE IRM channels are ≤ [25/40] divisions of full scale on Range 7. This requirement ensures that the plant will be shut down at > {110}°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

[Note that {25/40} divisions of full scale on IRM Range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP.] At this power level, heat input is approximately equal to normal system heat losses.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1 and 2 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > {95}°F,

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.2.1 - SUPPRESSION POOL AVERAGE TEMPERATURE

1. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, or analysis description.

2. The discussions of the four different concerns that lead to the development of the suppression pool average temperature limits have been deleted. The appropriate analysis is described in the USAR (References 1 and 2) and discussion in the Bases is not needed for understanding this Specification.

3. The brackets have been removed and the proper plant specific information/value has been provided.

4. Changes have been made to reflect those changes made to the Specification.

5. Typographical error corrected.

6. Editorial change made for enhanced clarity.

C

BASES

ACTIONS

A.1 (continued)

maintaining {secondary containment} during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring {secondary containment} OPERABILITY) occurring during periods where {secondary containment} is inoperable is minimal.

B.1 and B.2

If the {secondary containment} cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the {primary or secondary containment}, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the {secondary containment}. In such cases, the {secondary containment} is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the {secondary containment} is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

BASES

ACTIONS

1

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

movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

C

SURVEILLANCE REQUIREMENTS

1

SR 3.6.4.1.1

This SR ensures that the {secondary containment} boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to {secondary containment} vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal {secondary containment} vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

In each access opening

TSTF-18

one

1

Verifying that {secondary containment} equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the {secondary containment} will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining {secondary containment} OPERABILITY requires verifying each door in the access opening is closed, except when the access opening is being used for entry and exit, then, at least one door must remain closed. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

1

B

Insert SR3.6.4.3

TSTF-18

1

6

one

TSTF-18

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the [secondary containment] atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.4 verifies that the SGT System will rapidly establish and maintain a pressure in the [secondary containment] that is less than the lowest postulated pressure external to the [secondary containment] boundary. This is confirmed by demonstrating that one SGT subsystem will draw down the [secondary containment] to ≥ [0.25] inches of vacuum water gauge in ≤ [120] seconds. This cannot be accomplished if the [secondary containment] boundary is not intact. SR 3.6.4.1.5 demonstrates that each SGT subsystem can maintain ≥ [0.266] inches of vacuum water gauge for 1 hour at a flow rate ≤ [4000] cfm. The 1 hour test period allows [secondary containment] to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure [secondary containment] boundary integrity. Since these SRs are [secondary containment] tests, they need not be performed with each SGT subsystem. The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Insert SR3.6.4.1.4 and SR3.6.4.1.5

REFERENCES

1. USAR, Section 15.6.5.
2. FSAR, Section [15.7.6].
3. USAR, Section 15.7.4.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 6.2.2.4.

INSERT 3.6.4.1.4 and 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 2670 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that the secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds with the initial secondary containment pressure ≥ 0 psig, using one SGT subsystem. SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm. This flow rate is the assumed secondary containment leak rate during the drawdown period. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The drawdown test conditions must be adjusted based on the methodology in Reference 5 to compensate for actual inleakage flow and initial conditions during the test. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.4.1 - SECONDARY CONTAINMENT

1. The brackets have been removed and the proper plant specific information/value has been provided.

2. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, or analysis description.

3. Not used. 1C

4. Changes have been made to reflect those changes made to the Specification.

5. ISTS SRs 3.6.4.1.4 and 3.6.4.1.5 are tests that ensure the Secondary Containment is OPERABLE; the leak tightness of the Secondary Containment boundary is within the assumptions of the accident analyses. However, they are written in such a manner that they imply that if a SGT subsystem is inoperable, the SRs are failed ("Verify each standby gas treatment (SGT) subsystem will/can..."). As stated above, this is not the intent of the SRs. Therefore, to ensure this misinterpretation cannot occur, the SRs and this Bases description have been rephrased to more clearly convey the original intent of the SRs, to verify the Secondary Containment is OPERABLE. With the new wording, if a SGT subsystem is inoperable, SRs 3.6.4.1.4 and 3.6.4.1.5 will still be met and only the SGT System Specification, LCO 3.6.4.3, will be required to be entered. This is clearly identified in the Bases.

6. The Bases have been modified to provide additional clarity when describing the design of an access opening. 1B

BASES

APPLICABLE SAFETY ANALYSES (continued)

primary containment (Ref. 6), and a fuel handling accident in the auxiliary building (Ref. 4). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The automatic power operated, isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 6.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 6.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other

(continued)

BASES

ACTIONS

B.1 (continued)

with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. 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, D.2, and D.3

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the ~~primary and~~ secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated 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.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

Not locked, sealed or otherwise secured and is

This SR verifies each secondary containment isolation manual valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the {secondary containment} boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in {secondary containment} that are capable of being mispositioned are in the correct position.

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This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position since these were verified to be in the correct position upon locking, sealing, or securing.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

INSERT SR 3.6.4.2.1

SR 3.6.4.2.2

Verifying the isolation time of each power operated and each automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The ~~Isolation time and~~ Frequency of this SR ~~is in accordance with the Inservice Testing Program or~~ 92 days}.

TSTF-46

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1, E.2, and E.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be immediately

(continued)

BASES

ACTIONS

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

suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies

(continued)

L.7 CHANGE

Not used.

C

L.7 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The proposed change excludes the position verification of manual valves and blind flanges when the manual valves and blind flanges are locked, sealed or secured in the correct position. Secondary containment isolation is not considered an initiator of any previously analyzed accident. Therefore, this change will not involve an increase in the probability of an accident previously evaluated. This change only alters the method of verifying the position of manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position. This allowance is acceptable since the probability of misalignment of a locked, sealed, or secured manual valve or blind flange, once it has been verified to be in the proper position, is small. The position verification of these manual valves and blind flanges is still maintained (the verification is performed upon locking, sealing, or securing the manual isolation device in position). As a result, the accident consequences are unaffected by this change. Therefore, this change will not involve an increase in the consequences of an accident previously evaluated.

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

   This change does not introduce a new mode of plant operation and does not involve physical modification to the plant. The position verification of these manual valves and blind flanges is still maintained (the verification is performed upon locking, sealing, or securing the manual isolation device in position). Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated. C

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

   The proposed change excludes the position verification of manual valves and blind flanges when the manual valves and blind flanges are locked, sealed or secured in the correct position. This change only alters the method of verifying the position of manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position. This allowance is acceptable since the probability of misalignment of a locked, sealed, or secured manual valve or blind flange, once it has been verified to be in the proper position, is small. The position verification of these manual valves and blind flanges is still maintained (the verification is performed upon locking, sealing, or securing the manual isolation device in position). Eliminating the

L.7 CHANGE

3. (continued)

position verification of these manual valves and blind flanges in radiation areas increases safety to plant personnel and reduces exposure to plant personnel which is consistent with the As-Low-As-Reasonably-Achievable (ALARA) concept. Since the position verification of these manual valves and blind flanges is still maintained and the probability of misalignment of these manual valves and blind flanges is small due to the affected manual valves and blind flanges being locked, sealed, or secured in the correct position, this change does not involve a significant reduction in a margin of safety.

JUSTIFICATION FOR DEVIATION FROM NUREG-1434, REVISION 1
ITS: 3.7.2 - CONTROL ROOM ENVELOPE FILTRATION (CREF) SYSTEM

1. The Specification has been renumbered due to the deletion of ISTS 3.7.2.

2. The brackets have been removed and the proper plant specific information/value has been provided.

3. This bracketed requirement has been deleted because it is not applicable to NMP2.

4. The proper NMP2 plant specific nomenclature/value has been provided.

5. Typographical error corrected.

6. Due to the design of the NMP2 CREF System, the control room envelope pressurization test (ISTS SR 3.7.3.4) must be verified with all combinations of the CREF System (filter trains and air handling units) every 24 months. Therefore, the SR has been revised to be consistent with the NMP2 current licensing basis.

7. The NMP2 CREF System design includes two filter trains and four air handling unit fans. The filter trains provides the means of filtering the control room envelope recirculated and outside air makeup. The filter train booster fans, which are considered part of the filter trains, take a suction on the filter train and provide sufficient head to overcome the differential pressure loss as a result of the filter trains being in service. The filter train booster fans discharge into a common header. The air handling unit fans take a suction on the common header and provide the necessary head to pressurize the control room envelope to 1/8 inch positive pressure. Two air handling unit fans are necessary to provide the 1/8 inch positive pressure; one for the control room area and one for the relay room. Thus for the CREF System to perform its design function, one filter train and two air handling unit fans are required. Two CREF subsystems are provided, with each subsystem consisting of one filter train and two air handling unit fans, all from the same electrical power division. Due to this design, when both subsystems are inoperable, the capability for the CREF System to perform its design function may still exist. For example, if the Division 1 filter train and the Division 2 relay room air handling unit fan are inoperable, sufficient components are OPERABLE for the CREF System to meet its safety function (using the Division 2 filter train, the Division 1 relay room air handling unit fan, and either the Division 1 or 2 control room area air handling unit fan). Therefore, since this alignment is equivalent to having one CREF subsystem fully OPERABLE, the 7 day restoration time is acceptable, provided the CREF System safety function is maintained. The ISTS has been modified based on the NMP2 design. ISTS 3.7.3 Condition A (ITS 3.7.2 Condition A) has been modified to allow both CREF subsystems to be inoperable, provided the CREF safety function is maintained. The associated Required Action has also been modified to ensure all CREF subsystems are restored in the 7 day Completion Time. ISTS 3.7.3 Conditions D and E (ITS 3.7.2 Conditions D and E) have also been modified to specifically be applicable when both CREF subsystems are inoperable and the CREF safety function is not maintained. This is equivalent to the ISTS Conditions, since in the ISTS, with both CREF subsystems inoperable, the safety function may not be able to be performed

7. (continued)

(as described in the ISTS Bases for ACTION D). In addition, ISTS 3.7.3 Required Action C.1 (ITS 3.7.2 Required Action C.1) has been modified to ensure the OPERABLE components of one complete CREF subsystem are placed in operation, consistent with the ISTS intent. This is needed since ACTION C would be applicable with both CREF subsystems inoperable but safety function maintained. For further discussion, see Discussion of Change L.1 for ITS 3.7.2.

JUSTIFICATION FOR DEVIATION FROM NUREG-1434, REVISION 1
ITS: 3.7.3 - CONTROL ROOM ENVELOPE AIR CONDITIONING (AC) SYSTEM

1. The brackets have been removed and the proper plant specific information/value has been provided.

2. The Specification has been renumbered due to the deletion of ISTS 3.7.2.

3. The NMP2 Control Room Envelope AC System design includes four air handling units. Two air handling units are necessary to provide cooling to the control room envelope; one for the control room area and one for the relay room. Thus for the Control Room Envelope AC System to perform its design function, two air handling units are required. Two control room envelope AC subsystems are provided, with each subsystem including two air handling units, both from the same electrical power division. Due to this design, when both subsystems are inoperable, the capability for the Control Room Envelope AC System to perform its design function may still exist. For example, if the Division 1 control room area and the Division 2 relay room air handling units are inoperable, sufficient components are OPERABLE for the Control Room Envelope AC System to meet its safety function (using the Division 2 control room area air handling unit and the Division 1 relay room air handling unit). Therefore, since this alignment is equivalent to having one control room envelope AC subsystem fully OPERABLE, the 30 day restoration time is acceptable, provided the Control Room Envelope AC System safety function is maintained. The ISTS has been modified based on the NMP2 design. ISTS 3.7.4 Condition A (ITS 3.7.3 Condition A) has been modified to allow both control room envelope AC subsystems to be inoperable, provided the control room envelope AC safety function is maintained. The associated Required Action has also been modified to ensure all control room envelope AC subsystems are restored in the 30 day Completion Time. ISTS 3.7.4 Conditions D and E (ITS 3.7.3 Conditions D and E) have also been modified to specifically be applicable when both control room envelope AC subsystems are inoperable and the control room envelope AC safety function is not maintained. This is equivalent to the ISTS Conditions, since in the ISTS, with both control room envelope AC subsystems inoperable, the safety function may not be able to be performed (as described in the ISTS Bases for ACTION D). In addition, ISTS 3.7.4 Required Action C.1 (ITS 3.7.3 Required Action C.1) has been modified to ensure the OPERABLE components of one complete control room envelope AC subsystem are placed in operation, consistent with the ISTS intent. This is needed since ACTION C would be applicable with both control room envelope AC subsystems inoperable but safety function maintained. For further discussion, see Discussion of Change L.4 for ITS 3.7.3. C

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by, and immediately follow, without shutdown, a successful performance of SR 3.8.1.2. ---------- Verify each required DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 3960 kW and ≤ 4400 kW for Division 1 and 2 DGs, and ≥ 2340 kW and ≤ 2600 kW for Division 3 DG.	31 days
SR 3.8.1.4	Verify each required day tank contains ≥ 403 gal of fuel oil for Division 1 and 2 DGs and ≥ 282 gal for Division 3 DG.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each required day tank.	31 days
SR 3.8.1.6	Verify each required fuel oil transfer subsystem operates to automatically transfer fuel oil from the storage tank to the day tank.	62 days

1C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 13.20 seconds, 2. energizes auto-connected shutdown loads for Division 1 and 2 DGs only, through the associated automatic load sequence time delay relays, 3. maintains steady state voltage ≥ 3950 V and ≤ 4370 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes for Division 1 and 2 DGs and supplies permanently connected shutdown loads for ≥ 5 minutes for Division 3 DG.	24 months B C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each required DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start, achieves voltage ≥ 3950 V for Division 1 and 2 DGs and ≥ 3820 V for Division 3 DG, and frequency ≥ 58.8 Hz for Division 1 and 2 DGs and ≥ 58.0 Hz for Division 3 DG; b. Achieves steady state voltage ≥ 3950 V and ≤ 4370 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system for Divisions 1 and 2 only; and e. Emergency loads are auto-connected through the associated automatic load sequence time delay relays to the offsite power system for Divisions 1 and 2 only.	24 months C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load block, for the Division 1 and 2 DGs only, is ≥ 90% of the design interval for each automatic load sequence time delay relay.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. for Divisions 1 and 2, energizes auto-connected emergency loads through the associated automatic load sequence time delay relays and for Division 3, energizes auto-connected emergency loads, 3. maintains steady state voltage ≥ 3950 V and ≤ 4370 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3950 V is approximately 95% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 14), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4370 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 11).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period. In addition, to minimize wear and tear on the DG, the Note

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

also allows all DG starts to be followed by a warmup period prior to loading. (B)

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant (Division 1 and 2 DGs only) and lube oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 15). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 11). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0 when running synchronized with the grid. The 0.8 power factor value is the design rating of the machine at a particular KVA. The 1.0 power factor value is an operational condition where the reactive power component is zero, which minimizes the reactive heating of

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

the generator. Operating the generator at a power factor between 0.8 lagging and 1.0 avoids adverse conditions associated with underexciting the generator and more closely represents the generator operating requirements when performing its safety function (running isolated on its associated 4.16 kV emergency bus). The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 11).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance must be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which the low-low level alarm is annunciated. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is most effective means in controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is established by Regulatory Guide 1.137 (Ref. 13). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each fuel oil transfer pump (two per DG) operates and automatically transfers fuel oil from its associated storage tank to its associated day tank. It is required to support the continuous operation of standby power sources. This Surveillance provides assurance that each fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE. Two fuel oil transfer pumps per DG are required since each pump only has a simplex strainer.

The Frequency for this SR is conservative with respect to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 16). 1C

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined frequency and while maintaining a specified margin to the overspeed trip. The load referenced for Division 1 DG is the 1125 kW low pressure core spray pump; for Division 2 DG, the 750 kW residual heat removal (RHR) pump; and for Division 3 DG the 2435 kW HPCS pump. The specified load values conservatively bound the expected kW rating of the single largest loads under accident conditions. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

Consistent with Regulatory Guide 1.9 (Ref. 11), the load rejection test is acceptable if the diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower. This corresponds to ≤ 64.5 Hz for the Division 1 and 2 DGs and ≤ 66.75 Hz for the Division 3 DG, which is the nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed at a power factor as close to the power factor of the single largest post-accident load as practicable. The power factor limit is ≤ 0.92 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is representative of the actual design basis inductive loading that the DG could experience. However, since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.8

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.91 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

representative of the actual design basis inductive loading that the DG would experience.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.9

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads (Divisions 1 and 2 only) and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start and energization of permanently connected loads time of 13.20 seconds is derived from the 3.20 second Loss of Voltage—Time Delay Function Allowable Value (LCO 3.3.8.1) and the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 14). The Surveillance should be continued for a minimum of 18

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanently connected loads and auto-connected loads (Division 1 and 2 only) is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal). In addition,

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The DG is required to operate for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power (for Divisions 1 and 2 only).

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. This is only required for Divisions 1 and 2 because the loading logic is different based on the power source. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the AC electrical power system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths.

This SR is modified by two Notes. The reason for the Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed and generator differential current) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG and 2 hours of which is at a load equivalent to 105% to 110% of the continuous rating of the DG. The DG starts for this Surveillance can be performed

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.91 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is representative of the actual design basis inductive loading that the DG could experience.

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. However, it is acceptable to perform this SR in MODES 1 and 2 provided the other two DGs are OPERABLE, since a perturbation can only affect one divisional DG. If during performance of this Surveillance one of the other DGs becomes inoperable, this Surveillance is to be suspended. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid. 10

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.13

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 15). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at approximately full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

and can receive an auto-close signal on bus undervoltage, and the individual load timers are reset.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycles.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.15

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.13, demonstration of the parallel test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 17), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.10. The intent in the requirement associated with SR 3.8.1.15.b is to show that the emergency loading is not affected by the DG operation in parallel test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR has been modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.16

Under accident conditions loads are sequentially connected to the bus by the automatic load sequence time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The -10% load sequence time interval limit ensures that a sufficient time interval exists for the DG to restore frequency and voltage prior to applying the next load. There is no upper limit for the load sequence time interval since, for a single load interval (i.e., the time between two load blocks), the capability of the DG to restore frequency and voltage prior to applying the second load is not negatively affected by a longer than designed load interval, and if there are additional load blocks (i.e., the design includes multiple load intervals), then the lower limit requirements (-10%) will ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the remaining load blocks (i.e., all load intervals must be ≥ 90% of the design interval). Reference 2 provides a summary of the automatic loading of emergency buses. Since only the Division 1 and 2 DGs have more than one load block, this SR is only applicable to these DGs. C C

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

ACTIONS

A.1 (continued)

supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this situation, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of: 1E

a. The potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The low potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition A is entered while, for instance, a DC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.8.a, b, or c, to restore the AC electrical power

(continued)

Table B 3.8.8-1 (page 1 of 1)
AC, DC, and 120 VAC Uninterruptible Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a]	DIVISION 3[a]
AC buses	4160 V	Switchgear 2ENS*SWG101	Switchgear 2ENS*SWG103	Switchgear 2ENS*SWG102
	600V	Load Center 2EJS*US1 MCCs 2EHS*MCC101, 2EHS*MCC102, and 2EHS*MCC103 Distribution Panels 2EJS*PNL100A and 2LAC*PNL100A	Load Center 2EJS*US3 MCCs 2EHS*MCC301, 2EHS*MCC302, and 2EHS*MCC303 Distribution Panels 2EJS*PNL300B and 2LAC*PNL300B	MCC 2EHS*MCC201
	240/120 V			Distribution Panel 2SCV*PNL200P
	208/120 V			Distribution Panel 2LAC*PNLE03
DC buses	125 V	Switchgear 2BYS*SWG002A MCC 2DMS*MCCA1 Distribution Panels 2BYS*PNL201A, 2BYS*PNL202A, and 2BYS*PNL204A	Switchgear 2BYS*SWG002B MCC 2DMS*MCCB1 Distribution Panels 2BYS*PNL201B, 2BYS*PNL202B, and 2BYS*PNL204B	Distribution Panel 2CES*IPNL414
120 VAC uninterruptible panels	120 V	Distribution Panels 2VBS*PNL101A and 2VBS*PNL102A	Distribution Panels 2VBS*PNL301B and 2VBS*PNL302B	

(a) Each division of the AC, DC, and 120 VAC uninterruptible electrical power distribution system is a subsystem.

A.1

Specification 3.8.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

LIMITING CONDITIONS FOR OPERATION

3.8.1.1 (Continued)

ACTION:

ACTION D h. With one offsite circuit of the above-required AC electrical power sources inoperable and diesel generator EDG*2 inoperable, apply the requirements of ACTIONS a and d specified above. M.5

ACTION E i. With either diesel generator EDG*1 or EDG*3 inoperable and diesel generator EDG*2 inoperable, apply the requirements of ACTIONS b, d, and e specified above. M.6

j. With one or more diesel fuel storage tank(s) containing less than the minimum quantity of fuel oil but greater than or equal to 40,755 gallons of fuel for EDG*1 and EDG*3, or greater than or equal to 30,293 gallons for EDG*2, restore fuel oil to required levels within 48 hours or declare the affected diesel generator(s) inoperable. A.3 moved to LCO 3.8.3

k. With one or more diesel generator(s) with new diesel fuel oil properties not within limits, restore stored fuel oil properties to required limits within 30 days or declare the affected diesel generator(s) inoperable.

l. With one or more diesel generator(s) with stored fuel total particulates not within limits, restore stored fuel total particulates to required limits within 7 days or declare the affected diesel generator(s) inoperable.

add proposed ACTION G A.7

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be determined OPERABLE at least once every 7 days by verifying correct breaker alignments and indicated power availability.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE: L.2.3 C

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by: L.5

SR 3.8.1.4 1. Verifying the fuel level in the day fuel tank every 31 days L.6

2. Verifying the fuel level in the fuel storage tank. A.3 moved to LCO 3.8.3

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Specification 3.8.1

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.a (Continued)

SR3.8.1.6 3. Verifying each fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank every 62 days L.6 VG

SR3.8.1.2 4. Verifying that on a start from ambient conditions: M.7

a) That diesel engines EDG*1 and EDG*3 accelerate to at least 600 rpm in less than or equal to 10 seconds.* The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds and 4160 ± 420 volts and 60 ± 1.2 Hz within 13 seconds after the start signal. 210 1.2 L.7 210 M.7 L.8 LA.3

b) That diesel engine EDG*2 accelerates to at least 870 rpm and at least 3950 volts in less than or equal to 10 seconds.* The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 15 seconds after the start signal. 3820 210 M.7 LA.3

c) Each diesel generator shall be started for this test by using one of the following signals: 4.8

1) Manual.

2) Simulated loss of offsite power by itself.

3) Simulated loss of offsite power in conjunction with an ESF actuation test signal.

4) An ESF actuation test signal by itself.

add proposed Note 2 L.9

add proposed Notes 3 and 4 M.8

SR3.8.1.3 5. Verifying that after the diesel generator is synchronized, it is loaded to greater than or equal to 4400 KW for diesel generators EDG*1 and EDG*3 and greater than or equal to 2600 KW for diesel generator EDG*2 in less than or equal to 90 seconds* and operates with these loads for at least 60 minutes. 3960 kw and ≤ 2340 kw and ≤

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency buses. L.10 L.11

SR3.8.1.2* Note 1 All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized. L.10 B

SR3.8.1.2 Note 2

SR3.8.1.3 Note 1

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

LD.1

4.8.1.1.2 (Continued) 24 L.13

e. At least once per 18 months, 6 during shutdown, by: A.9

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service. LA.4 M.9

add proposed Note 2 to SR 3.8.1.7

SR 3.8.1.7 2. Verifying the diesel generator capability to reject a load of greater than or equal to 1125 kW for diesel generator EDG*1, greater than or equal to 750 kW for diesel generator EDG*3, and greater than or equal to 2423 kW for diesel generator EDG*2 while maintaining engine speed increase less than or equal to 75% of the difference between nominal speed and the overspeed trip setpoint or 15% of nominal, whichever is less. LA.5 its associated single largest post-accident load M.14 A.10

add proposed Note 2 to SR 3.8.1.8

SR 3.8.1.8 3. Verifying the diesel generator capability to reject a load of 4400 kW for diesel generators EDG*1 and EDG*3 and 2600 kW for diesel generator EDG*2 without tripping.** The generator voltage shall not exceed 4576 volts for EDG*1 and EDG*3, and 5824 volts for EDG*2 during and following the load rejection. M.9 while operating within the Power Factor Limit 2 A.11

SR 3.8.1.9 4. Actual or Simulating a loss of offsite power by itself, and: L.14

a) For Divisions I and II:

1) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

2) Verifying the diesel generator starts*** on the autostart signal, energizes the emergency buses with permanently connected loads within 13 seconds†, energizes the auto-connected (shutdown) loads through the load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test. L.15 13.20 A.7 210 L.13

* For any start of a diesel, the diesel must be operated with a load in accordance with the manufacturer's recommendations.

** Momentary transients due to changing bus loads shall not invalidate the test. A.11

SR 3.8.1.9 Note 1 *** All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized. A.12

SR 3.8.1.9 † From initiation of loss of offsite power.

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.e (Continued)

SR 3.8.1.17

6. Simulating actual or a loss of offsite power in conjunction with an ECCS actuation test signal, and: L.14

a) For Divisions I and II:

1) Verifying deenergization of the emergency buses and loads shedding from the emergency buses.

2) Verifying the diesel generator starts* on the autostart signal, energizes the emergency buses with permanently connected loads within 10 seconds, energizes the auto-connected (shutdown) loads through the load timers, and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test. 210 M.7 1C

b) For Division III:

1) Verifying deenergization of the emergency bus.

2) Verifying the diesel generator starts* on the autostart signal, energizes the emergency bus with the permanently connected loads and the auto-connected emergency loads within 10 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test. LA.7 auto connected loads only 210 M.7

SR 3.8.1.11 7. Verifying that actual or simulated all automatic diesel generator trips are automatically bypassed upon loss of voltage on the emergency bus concurrent with an ECCS actuation signal except engine overspeed trip and generator differential trip. L.14

SR 3.8.1.17 Note 1

* All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Furthermore, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized. A.12

A.13

Specification 3.8.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.e (Continued)

SR 3.8.1.16 12. Verifying that the automatic load timer relays are OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators EDG*1 and EDG*3. L.24 | C

L.18 add proposed Note 2

13. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required: L.17

a) For Divisions I and II, turning gear engaged and emergency stop.

b) For Division III, engine in the maintenance mode and diesel generator lockout. LD.1

SR 3.8.1.13 f. At least once per 18 (24) months verify each diesel generator starts and accelerates to at least 600 RPM within 10 seconds for EDG*1 and EDG*3, and 870 RPM within 10 seconds for EDG*2. The generator voltage and frequency for EDG*1 and EDG*3 shall be 4160 ± 416 volts and 60 ± 3.0 Hz within 10 seconds and 4160 ± 416 volts and 60 ± 1.2 Hz within 13 seconds after the start signal. The generator voltage and frequency for EDG*2 shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 16 seconds after the start signal. This test shall be performed within 5 minutes of shutting down the diesel generator after the diesel generator has operated for at least 2 hours at 4400 kW or more for EDG*1 and EDG*3 and 2600 kW or more for EDG*2. For any start of a diesel, the diesel must be loaded in accordance with manufacturer's recommendations. Momentary transients due to changing bus loads shall not invalidate this test. L.7 M.7 210 L.8 1.2 L.7 210 M.7 LA.3 210 M.7 3960 2340 L.9 L.A.3

23820V in ≤10 seconds and

add proposed Note to SR 3.8.1.18

SR 3.8.1.18 g. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all three diesel generators simultaneously, during shutdown, and verifying that all diesel generators EDG*1 and EDG*3 accelerate to at least 600 rpm and EDG*2 accelerates to at least 870 rpm in less than or equal to 10 seconds. L.13 L.18 L.19 L.20 58.8 Hz

h. At least once per 10 years by: add proposed voltage limits M.13 L.7

1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and A.3 moved to LCO 3.8.3

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

4.8.1.1.3 All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.2, within 30 days. Reports of diesel generator failures shall include the information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977. L.21

Specification 3.8.1

A.1

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

2.23 | C

NUMBER OF FAILURES IN LAST 20 VALID TESTS*	NUMBER OF FAILURES IN LAST 100 VALID TESTS*	TEST FREQUENCY
≤1	≤4	At least once per 31 days
≥2**	≥5	At least once per 7 days

* Criteria for determining number of failures and number of valid tests shall be in accordance with Position C.2.e of RG 1.108, but determined on a per diesel generator basis.

For the purposes of determining the required test frequency, the previous test failure count may be reduced to zero if a complete diesel overhaul to like-new condition is completed, provided that the overhaul, including appropriate postmaintenance operation and testing, is specifically approved by the manufacturer and if acceptable reliability has been demonstrated. The reliability criterion shall be the successful completion of 14 consecutive tests in a single series. Ten of these tests shall be in accordance with the routine Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 and four tests in accordance with the 184-day testing requirement of Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5. If this criterion is not satisfied during the first series of tests, any alternate criterion to be used to transvalue the failure count to zero requires NRC approval.

** The associated test frequency shall be maintained until seven consecutive failure-free demands have been performed and the number of failures in the last 20 valid demands has been reduced to 1.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.8 (cont'd) SR be immediately preceded by a successful performance of SR 3.8.1.2 (the DG start Surveillance). This will ensure the DG load carrying capability is tested subsequent to a successful DG start test. While these Notes clearly represent current NMP2 practice, they are more restrictive than the CTS since the SR could currently be performed without these restrictions.

M.9 Limitations on the operating power factor are added to CTS 4.8.1.1.2.e.2, the single load rejection test (proposed Note 2 to SR 3.8.1.7), CTS 4.8.1.1.2.e.3, the full load rejection test (proposed SR 3.8.1.8, including Note 2), and CTS 4.8.1.1.2.e.8, the 24-hour run Surveillance (proposed SR 3.8.1.12, including Note 3). These limitations ensure the DG is conservatively tested at as close to accident conditions as reasonable, provided the power factor can be attained. The actual power factor values have been added to the Bases. A Note has been also added to CTS 4.8.1.1.2.e.8 (proposed SR 3.8.1.12 Note 1) to ensure a momentary transient that results in the power factor not being met does not invalidate the 24 hour run. These changes are more restrictive on plant operation.

M.10 CTS 4.8.1.1.2.e.5.a) requires the Division 1 and 2 DGs accelerate to 57 Hz (60 Hz - 3.0 Hz) within 10 seconds. CTS 4.8.1.1.2.e.5.b) does not provide any minimum voltage or frequency the Division 3 DG must meet within the 10 second DG start time assumed in the accident analysis. Proposed SR 3.8.1.10 requires the minimum frequency for Division 1 and 2 DGs to be 58.8 Hz and requires the minimum voltage and frequency for the Division 3 DG to be 3820 V and 58.0 Hz, respectively. The frequency for Division 1 and 2 DGs is consistent with Regulatory Guide 1.9, Rev. 3 and with the steady state frequency limit the DGs are currently required to maintain. The frequency for Division 3 DG is consistent with CTS 4.8.1.1.2.a.4.b). The voltage ensures that components powered by the associated bus will have sufficient voltage to perform their required function. These are additional restrictions on plant operation.

M.11 Two new requirements have been added to CTS 4.8.1.1.2.e.5.a). SR 3.8.1.10.d and SR 3.8.1.10.e ensure that Division 1 and 2 permanently connected loads remain energized from the offsite power system and that Division 1 and 2 emergency loads are autoconnected through the associated automatic load sequence time delay relays to the offsite power system. This is required since separate load timers are used to autoconnect some of the Division 1 and 2 emergency loads to the offsite power system, and if the proper load timer does not operate, an offsite circuit could be impacted. This is an additional restriction on plant operation. C B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.2 Not used.

LA.3 CTS 4.8.1.1.2.a.4, 4.8.1.1.2.e.5, and 4.8.1.1.2.f provide requirements on DG voltage and frequency for two distinct times. The second time is when the DG is essentially at steady state conditions. These details of when the DGs are at essentially the steady state conditions (13 seconds after the start signal for Division 1 and 2 DGs and 15 seconds for the Division 3 DG) are proposed to be relocated to the Bases. In their place, a statement has been provided in proposed SR 3.8.1.2, SR 3.8.1.10, and SR 3.8.1.13 that voltage and frequency limits are applicable after steady state conditions have been achieved. These relocated details are not necessary to ensure the OPERABILITY of the DGs. The requirements of ITS 3.8.1 and the associated Surveillance Requirements are adequate to ensure the DGs are maintained OPERABLE. As such, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.4 The requirement of CTS 4.8.1.1.2.e.1 to inspect the DGs in accordance with procedures prepared in accordance with manufacturer's recommendations, is proposed to be relocated to the USAR. This inspection is a preventative maintenance type requirement. The failure to perform this requirement does not necessarily result in an inoperable DG. This requirement is oriented toward long term DG OPERABILITY and does not have an immediate impact on DG OPERABILITY. DG OPERABILITY is verified by the SRs maintained in ITS 3.8.1. In addition, USAR controls on DG inspections recommended by the manufacturer are sufficient to ensure the DG receives the necessary inspections. As a result, this requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59.

LA.5 The CTS 4.8.1.1.2.e.2 specific kilowatt value of the single largest post-accident load for the single load rejection Surveillance Requirement is proposed to be relocated to the Bases. The reference to the specific value of the single largest post-accident load within the Technical Specifications is not necessary to adequately present the requirement. The value of the load, as well as the component itself, are specifically detailed in the Bases. These details are not necessary to ensure the OPERABILITY of the diesel generators. The requirements of ITS 3.8.1 and the associated Surveillance Requirements (including SR 3.8.1.7) for the diesel generators are adequate to ensure the diesel generators are maintained OPERABLE. As such, the relocated details are not required to be in the ITS to provide adequate protection of the public

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.5 (cont'd) health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.6 CTS 4.8.1.1.2.e.9, which addresses the specific load value for the auto-connected loads, is proposed to be relocated to the USAR. The specific load value for the autoconnected loads on the diesel generators is a design detail. These details are not necessary to ensure the OPERABILITY of the diesel generators. The definition of OPERABILITY, the requirements of ITS 3.8.1, and the associated Surveillance Requirements for the diesel generators are adequate to ensure the diesel generators are maintained OPERABLE. Changes to the USAR are controlled by 10 CFR 50.59. In addition, any change to the loads placed on the DG will be controlled by 10 CFR 50.59 (a design change is required to change the actual loads). As such, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety.

LA.7 The requirement of CTS 4.8.1.1.2.e.6.b) that the auto-connected loads be energized "within 10 seconds" for Division 3 is proposed to be relocated to the Bases in a discussion of the DG loading logic. The loads are designed to be connected only through the loading logic, thus if they are not energized, the SR has failed. Therefore, this detail is not necessary to ensure the OPERABILITY of the Division 3 diesel generator. The requirements of ITS 3.8.1, and the associated Surveillance Requirements for the Division 3 diesel generator are adequate to ensure the diesel generators are maintained OPERABLE. In addition, the 10 second requirement for Division 3 was based upon the HPCS Response Time, not the actual loading of the DG. The HPCS Response Time is already required by ITS 3.5.1 and does not need to be repeated in this Specification. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS. C C

LD.1 The Frequency for performing CTS 4.8.1.1.2.e.2, 4.8.1.1.2.e.3, 4.8.1.1.2.e.4, 4.8.1.1.2.e.5, 4.8.1.1.2.e.6, 4.8.1.1.2.e.7, 4.8.1.1.2.e.8, 4.8.1.1.2.e.10, 4.8.1.1.2.e.11, 4.8.1.1.2.e.12, and 4.8.1.1.2.f (proposed SRs 3.8.1.7, 3.8.1.8, 3.8.1.9, 3.8.1.10, 3.8.1.17, 3.8.1.11, 3.8.1.12, 3.8.1.14, 3.8.1.15, 3.8.1.16, and 3.8.1.13, respectively) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refuel cycle from 12 months to 24 months. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) specified in CTS 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 In the event of multiple concurrent AC Source inoperabilities (i.e., one Division 1 or 2 DG and one offsite circuit) the existing Actions limit restoration time to 72 hours from the time of initial loss of the first AC Source (CTS 3.8.1.1 Action c). When a second inoperability occurs just prior to restoration of the initial inoperability and close to the expiration of the initial 72 hours, this limitation can provide little or no time to effect repair. The result would be a forced shutdown of the unit. While these simultaneous inoperabilities are expected to be rare, it is also expected that any AC source inoperability would be repaired in a reasonable time (≤ 72 hours). Given the minimal risk of an event during the repair of the subsequent inoperability, the likelihood of a satisfactory return to OPERABLE, and the risks involved with introducing plant transients associated with a forced shutdown, it is proposed to allow a separate time period for this subsequent repair. Since this rationale can be taken to extreme with continuous multiple overlapping inoperabilities, a maximum restoration time limit is imposed. The ITS format presents this as an additional Completion Time of "6 days from discovery of failure to meet LCO" in ITS 3.8.1 Required Actions A.3 and B.4.

In addition, in the event of multiple DG inoperabilities (Division 1 and 2) or multiple offsite circuit inoperabilities, the existing Actions limit restoration time to 72 hours from the time of initial loss (CTS 3.8.1.1 Actions f and g). The consequences and occurrences of the multiple inoperabilities is similar to that described in the first paragraph. Therefore, a separate time period is allowed for the subsequent repair. This time period is described in ITS 1.3, and essentially allows extension of the initial restoration time by 24 hours, not to exceed the actual time if the subsequent inoperability were tracked from its time of loss. The ITS 1.3 limits the subsequent inoperability extension to one use,

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L.1 (cont'd) i.e., the second inoperability can be extended, but not a third or subsequent inoperability. This is fully described in ITS 1.3.

L.2 CTS 3.8.1.1 Actions b, c, d, and g footnote * states "This is required to be completed regardless of when the inoperable diesel generator is restored to OPERABLE status. The provisions of Specification 3.0.2 are not applicable." This requirement (to verify the cause of the inoperable DG does not impact the other DG) is proposed to be deleted. The intent of this requirement is related to the determination that no common cause failure exists, whether or not the originally discovered inoperable DG has already been restored. "Common cause" evaluations are required by the NMP2 Deviation Event Report (DER) Program for all significant safety related deficiencies (as would be the case for inoperable DGs). The program requires "prompt" completion of the evaluation and actions to preclude its recurrence, regardless of whether the initial corrective action is completed. The DER Program (required by 10 CFR 50, Appendix B) should adequately assure the necessary evaluations are completed in a timely manner without necessitating abnormal requirements within the ITS.

L.3 CTS 3.8.1.1 Actions c and g require a verification that the cause of a DG inoperability does not affect the remaining DGs. This is verified by an evaluation or test within 8 hours. ITS 3.8.1 Required Actions B.3.1 and B.3.2 will continue to require this verification, but will allow 24 hours to perform the verification. This time is consistent with GL 84-15, which stated that the 24 hours was a reasonable time to perform the verification. This will allow more attention to be focused on restoring the inoperable DG, in lieu of testing the remaining OPERABLE DGs. This time is also consistent with that provided in CTS 3.8.1.1 Actions b and d, when one Divisional DG is inoperable (or two Divisional DGs are inoperable if both Actions are entered concurrently, as allowed by CTS 3.8.1.1 Action i). This extension is acceptable since the remaining DGs are routinely found to be OPERABLE during this verification. This change is also consistent with the time approved for WNP-2, which has a similar DG electrical distribution design (i.e., three divisionalized DGs), in their recent ITS amendment.

L.4 The Completion Time for CTS 3.8.1.1 Action e, to verify that required systems, subsystems, trains, components, and devices powered from the redundant DG(s) are OPERABLE has been extended from 2 hours to 4 hours in ITS 3.8.1 Required Action B.2. This Completion Time will allow the operator time to evaluate and repair any discovered inoperabilities, which minimizes the risk due to subjecting the unit to transients associated with a shutdown. The Completion Time also considers the capacity and capability of the remaining AC sources and the low probability of a DBA occurring during this period.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.5 CTS 4.8.1.1.2.a requires the normal monthly DG Surveillances to be performed on a STAGGERED TEST BASIS. Proposed SRs 3.8.1.2, 3.8.1.3, 3.8.1.4, and 3.8.1.6 do not include the STAGGERED TEST BASIS requirement. The intent of a requirement for staggered testing is to increase reliability of the component/system being tested. A number of reviews/evaluations have been performed which have demonstrated that staggered testing has negligible impact on component reliability. As a result, it has been determined that staggered testing 1) is operationally difficult, 2) has negligible impact on component reliability, 3) is not as significant as initially thought, 4) has no impact on failure frequency, 5) introduces additional stress on components such as DGs potentially causing increased component failure rates and component wearout, 6) results in reduced redundancy during testing, and 7) increases likelihood of human error by increasing testing intervals. Therefore, the DG staggered testing requirements have been deleted.

L.6 The Surveillance Frequency for CTS 4.8.1.1.2.a.1 (proposed SR 3.8.1.4), the day tank level check and CTS 4.8.1.1.2.a.3 (proposed SR 3.8.1.6), the fuel oil transfer pump test, has been changed from "frequency specified in Table 4.8.1.1.2-1" (the DG Test Schedule Table) to "31 days" for CTS 4.8.1.1.2.a.1 and "62 days" for CTS 4.8.1.1.2.a.3. This is because DG failures that result in a more frequent DG test frequency have no impact on the day tank's and the fuel oil transfer pump's ability to perform their intended function since the day tanks are normally maintained well above the minimum level and the auto start of the fuel oil transfer pumps. In addition, the 62 day transfer pump frequency is still conservative with respect to the ASME Section XI requirements for similar pumps (ASME Section XI is normally 92 days). 1 C 1 C

L.7 CTS 4.8.1.1.2.a.4.a) and 4.8.1.1.2.f require the Division 1 and 2 DGs to accelerate to 600 rpm in ≤ 10 seconds. For these DGs, 600 rpm is equivalent to a frequency of 60 Hz. The CTS requirements listed above further state that the generator frequency must be 60 ± 3.0 Hz in ≤ 10 seconds. In addition, once steady state is achieved, the frequency is required to be maintained at 60 ± 1.2 Hz. The ITS will require the minimum frequency to be 58.8 Hz, as shown in proposed SR 3.8.1.2 and 3.8.1.13. As shown above, the CTS has two different frequency requirements for the 10 second start time; 60 Hz and 57 Hz, with the 60 Hz limit the most limiting. The accident analysis requires the DG to be capable of being loaded within 10 seconds. This can be accomplished at 58.8 Hz. It is not necessary to require the DG frequency to be at 60 Hz in order to load the DG. In addition, the steady state frequency is already allowed to be at a minimum of 58.8 Hz. This new minimum frequency is also consistent with Regulatory Guide 1.9, Rev. 3, from which the ITS SR is derived.

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L.7 (cont'd) CTS 4.8.1.1.2.g also requires the Division 1 and 2 DGs to accelerate simultaneously to 600 rpm in ≤ 10 seconds. No additional frequency requirement, similar to the two CTS Surveillances described above, are provided. Proposed SR 3.8.1.18 provides a frequency requirement of 58.8 Hz. As stated above, the accident analysis requires the DG to be capable of being loaded within 10 seconds, and this can be accomplished at 58.8 Hz.

L.8 The requirements of CTS 4.8.1.1.2.a.4, 4.8.1.1.2.e.5, and 4.8.1.1.2.f (proposed SR 3.8.1.2, SR 3.8.1.10, SR 3.8.1.13) have been changed to only require the minimum voltage and frequency limits to be met within the appropriate time limits. Once steady state conditions are reached, the minimum and maximum voltage and frequency limits must be maintained. The tests in question are those that automatically start the DG but do not tie it to a bus. Verification that the minimum voltage and frequency limits are met within the proper time is sufficient to ensure the DG can perform its design function. When called upon, the DG must start and tie within the proper time. Once the minimum voltage and frequency limits are met, the DG can tie to the bus. When a test is performed that does not result in tieing the DG to the bus, a voltage or frequency overshoot can occur since no loads are being tied (the loading tends to minimize the overshoot). This overshoot could be such that the voltage or frequency is outside the band high when the time limit expires. This condition however, is not indicative of an inoperable DG, provided that steady state voltage and frequency are maintained. The steady state limit requirements have not been changed.

L.9 The load requirements of CTS 4.8.1.1.2.a.5 and CTS 4.8.1.1.2.e.8 (the 22-hour load requirements only) have been relaxed to ensure that the DG's continuous rating is not required to be exceeded on a routine basis. The new load range in proposed SR 3.8.1.3 and SR 3.8.1.12 is 90%-100% of the continuous rating for the DGs (3960 kW to 4400 kW for the Division 1 and 2 DGs and 2340 kW to 2600 KW for the Division 3 DG). These values are consistent with the recommendations of Regulatory Guide 1.9, Rev. 3, which recommends a load range of 90%-100%. The 2-hour load requirements of Surveillance 4.8.1.1.2.e.8 have also been relaxed. The new load range in proposed SR 3.8.1.12 is 105%-110% of the continuous rating for the DGs (4620 kW to 4840 kW for the Division 1 and 2 DGs and 2730 kW to 2860 kW for the Division 3 DG). These values are consistent with the recommendations of Regulatory Guide 1.9, Rev. 3, which recommends a load range of 105%-110%. These values will preclude routine overloading of the DG and the lower value will still ensure the DG is at operating temperatures. These proposed Surveillance Requirements still provides assurance that the DGs will carry normal loads. The 24 hour run test (proposed SR 3.8.1.12) will continue to ensure that the DGs can carry rated load.

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L.9 (cont'd) The load requirements of CTS 4.8.1.1.2.f have also been changed in proposed SR 3.8.1.13 Note 1 to conform to this load value (the lower limits of 3960 kW for the Division 1 and 2 DGs and 2340 kW for the Division 3 DG). This also will preclude routine overloading of the DGs and the lower value will still ensure the DG is at operating temperatures.

In addition, a Note has been added to CTS 4.8.1.1.2.a.5 (proposed SR 3.8.1.3 Note 2) stating that momentary transients outside the load range do not invalidate the Surveillance. This is to account for momentarily changing bus loads and precludes re-performance of the Surveillance solely due to the load being outside the load range as a result of a momentary transient. Demonstration of the load carrying capability and the ensurance of the DG at proper operating temperatures continue to be adequately tested because momentary transients are of short duration compared to the Surveillance test duration. This Note is also consistent with similar allowances of CTS 4.8.1.1.2.e.8 and 4.8.1.1.2.f.

L.10 The CTS 4.8.1.1.2.a.5 90-second limitation on the time to reach full DG load from a manual synchronization, required to be performed every 184 days as stated in footnote * to CTS 4.8.1.1.2.a.5, as well as the restriction to warming up the DG prior to loading, are proposed to be deleted. DG warmup and loading should be done in accordance with manufacturer's recommendations to minimize wear on the engine. Additionally, placing a time limitation on the operator to accomplish this loading results in an increased potential for error and subsequent unavailability of the DG. The starting, loading, subsequent full load operation, and automatic start and loading testing required by other ITS 3.8.1 Surveillance Requirements is adequate to confirm the DG's capability without the warmup restriction and 90-second loading requirement. 1B

L.11 CTS 4.8.1.1.2.a.6 requires verification that each DG is aligned to provide standby power to the associated emergency buses. The requirements of ITS 3.8.1, which require the DGs to be OPERABLE, and the associated Surveillance Requirements for the DGs are adequate to ensure the DGs are maintained OPERABLE. In addition, the definition of OPERABILITY and procedural controls on DG standby alignment are sufficient to ensure the DG remains aligned to provide standby power. In general, this type of requirement is addressed by plant specific processes which continuously monitor plant conditions to ensure that changes in the status of plant equipment that require entry into ACTIONS (as a result of failure to maintain equipment OPERABLE) are identified in a timely manner. This verification is an implicit part of using Technical Specifications and determining the appropriate Conditions to enter and Actions to take in the event of inoperability of Technical Specification equipment. In addition, plant and equipment status is continuously monitored

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) by control room personnel. The results of this monitoring process are documented in records/logs maintained by control room personnel, as required. The continuous monitoring process includes re-evaluating the status of compliance with Technical Specification requirements when Technical Specification equipment becomes inoperable using the control room records/logs as aids. Therefore, the explicit requirement to periodically verify that each DG is aligned to provide standby power to the associated emergency buses is considered to be unnecessary for ensuring compliance with the applicable Technical Specification OPERABILITY requirements and is to be removed from the Technical Specifications.

L.12 CTS 4.8.1.1.2.b.1 requires checking for and removing accumulated water from the DG day tanks every 31 days and "after each occasion when the diesel is operated for more than 1 hour." Proposed SR 3.8.1.5 only requires the check every 31 days; the frequency of "after each occasion when the diesel is operated for more than 1 hour" has been deleted. Water condensation within the fuel oil tanks is a time dependent process, not a process dependent on the transfer of fuel oil during DG operation. Furthermore, the fuel oil storage tank is similarly maintained free of accumulated water (CTS 4.8.1.1.2.b.2 and proposed SR 3.8.3.5). In the event the DG is not operated except for the nominal monthly OPERABILITY tests (which is the expectation), no increased Frequency is applied.

L.13 CTS 4.8.1.1.2.e footnote * and CTS 4.8.1.1.2.f require the diesel to be operated with a load in accordance with the manufacturer's recommendations any time the diesel is started to perform the Surveillances of CTS 4.8.1.1.2.e and CTS 4.8.1.1.2.f. The ITS does not include this requirement. This requirement is essentially a preventative maintenance type of requirement. The failure to perform this requirement does not necessarily result in an inoperable DG. This requirement is oriented toward long term DG OPERABILITY and does not have an immediate impact on DG OPERABILITY. In cases where the DG is started and not loaded, plant practice is to restart the DG and run it loaded for the manufacturer recommended time. In these cases, the DG normally starts properly; i.e., it is not found inoperable just because it was not loaded after a start. In addition, Generic Letter 83-28 required that utilities ensure that vendor recommended practices in vendor manuals be properly implemented in plant procedures. NMP2 has complied with this Generic Letter (specifically as it relates to the DGs). Therefore, this requirement is not necessary to be maintained in the ITS.

L.14 The phrase "actual or", in reference to the loss of offsite power signal or the ECCS actuation signal, as applicable, has been added to CTS 4.8.1.1.2.e.4, 4.8.1.1.2.e.5, 4.8.1.1.2.e.6, 4.8.1.1.2.e.7, and 4.8.1.1.2.e.11 (proposed

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L.14 (cont'd) SRs 3.8.1.9, 3.8.1.10, 3.8.1.17, 3.8.1.11, and 3.8.1.15, respectively) for verifying the proper response of the DG. This allows satisfactory loss of offsite power or ECCS actuations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. OPERABILITY is adequately demonstrated in either case since the DG cannot discriminate between "actual" or "simulated" signals.

L.15 CTS 4.8.1.1.2.e.4.a)2) and 4.8.1.1.2.e.4.b)2) require the DGs to start and energize the emergency buses within 13 seconds of a loss of offsite power signal. Proposed SR 3.8.1.9 will allow the DGs to start and energize the emergency buses within 13.20 seconds. This proposed time is the summation of the current DG start time of 10 seconds (from various CTS 4.8.1.1 Surveillances) and the DG loss of voltage time delay Allowable Value (from CTS Table 3.3.3-2 Trip Functions D.1 and E.1, as modified by an "L" Discussion of Change in ITS 3.3.8.1). This is also the time assumed in the accident analysis for the DG to start when only a loss of voltage occurs. The current time in CTS 4.8.1.1.2.e.4.a)2) and b)2) is essentially the allowed DG start and energization time rounded to the nearest whole second. Therefore, this change is effectively making the DG start and energization time of CTS 4.8.1.1.2.e.4.a)2 and b)2) consistent with the current allowed times in other portions of the CTS (as modified by an appropriate Discussion of Change in ITS 3.3.8.1). (B) (B) (B)

L.16 The manner in which the DG is started for CTS 4.8.1.1.2.e.8 (i.e., that the DG must be within the proper voltage and frequency within a certain time limit after the start signal) has not been included in proposed SR 3.8.1.12. While this test can be performed only after a fast start, the manner in which the DG is started does not affect the test. In addition, maintaining voltage and frequency (as required by CTS 4.8.1.1.2.e.8) is routine for this test to ensure the loads are maintained within the necessary limits, and does not need to be specified. Other Surveillance Requirements being maintained in the ITS (e.g., CTS 4.8.1.1.2.a.4, proposed SR 3.8.1.2) continue to require verifying the DG start time and voltage and frequency limits. If these limits are found not to be met during the performance of proposed SR 3.8.1.12, then the DG would be declared inoperable. As a result, these requirements are not necessary to be included in the Technical Specifications to ensure the diesel generators are maintained OPERABLE.

L.17 CTS 4.8.1.1.2.e.13, which verifies the DG lockout features prevent DG starting only when required, is proposed to be deleted. If a DG lockout feature prevents the DG from operating during an accident, this will still be identified during the LOCA, LOOP, and LOCA/LOOP DG Surveillances (proposed SRs 3.8.1.9, 3.8.1.10, and 3.8.1.17), which are currently performed at the

TECHNICAL CHANGES - LESS RESTRICTIVE

L.17 (cont'd) same periodicity as this Surveillance. It will also be identified during the normal 31 day test, proposed SR 3.8.1.2. Failure of a lockout feature to properly lockout a DG is not a concern as it relates to meeting accident analysis assumptions, since the DG would already be assumed not to be functioning (the lockout features are used to prevent the DG from starting on an accident signal). Therefore, removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY.

L.18 A Note to CTS 4.8.1.1.2.f and 4.8.1.1.2.g (proposed SR 3.8.1.13 and SR 3.8.1.18) has been added to allow a prelube prior to starting the DG. DG starts without prior engine prelube create unnecessary engine wear, thereby reducing overall reliability. The engine prelube does not result in an enhanced start performance that could mask the engine's inability to start in accident conditions without a prelube. This Note is also consistent with the allowance provided in all other DG starts required by the CTS.

L.19 Explicit post maintenance Surveillance Requirements as required by CTS 4.8.1.1.2.g (i.e., after any modifications which could affect DG interdependence) have been deleted. Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, ITS SR 3.0.1 requires the appropriate SRs (in this case, SR 3.8.1.18) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not repaired and have been deleted from the Technical Specifications.

L.20 The requirement to perform CTS 4.8.1.1.2.g during shutdown has not been included in proposed SR 3.8.1.18. The proposed Surveillance (to simultaneously start all three DGs) does not include the restriction on plant conditions. The Surveillance can be adequately tested in the operating conditions without jeopardizing safe plant operations, since the Surveillance does not require the DGs to be connected to their respective buses; the Surveillance only requires a start of the DGs. The control of plant conditions appropriate to perform the Surveillance is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.21 CTS 4.8.1.1.3, which requires that all DG failures be reported to the NRC in a special report pursuant to CTS 6.9.2, is proposed to be deleted. This requirement is proposed to be removed from Technical Specifications in accordance with the guidance of Generic Letter 94-01. GL 94-01 allows DG failure reporting requirements to be removed, but licensees must continue to comply with reporting requirements of 10 CFR 50.72 and 50.73, which may require notifying and reporting DG failures to the NRC. Also, this change does not impact the safe operation of the plant because the report is submitted after the DG failure has occurred and does not require NRC approval. Therefore, this requirement is being removed from the Technical Specifications consistent with the guidance of GL 94-01.

L.22 If an offsite circuit is inoperable only due to its inability to provide power the Division 3 electrical power distribution subsystem, CTS 3.8.1.1 Action a would require a unit shutdown if the offsite circuit is not restored to OPERABLE status within 72 hours. ITS 3.8.1 provides an Applicability Note which, in the event the HPCS System is inoperable, allows the Division 3 offsite circuits to not be required to be OPERABLE. Thus, at the end of the current 72 hour restoration time, the ITS Note would allow HPCS to be declared inoperable, and the ACTIONS in ITS 3.5.1 would be taken for an inoperable HPCS System. The ACTIONS in ITS 3.5.1 allow 14 days to restore HPCS to OPERABLE status. The overall effect of this change is to allow an additional 14 days to restore the circuit to OPERABLE status, since that is the only way to restore the HPCS System to OPERABLE status under this condition. The 14 day allowance is consistent with the allowance already provided in CTS 3.8.1.1 Action d for when the HPCS DG is inoperable. The two conditions (i.e., loss of the offsite circuit and loss of DG) are essentially the same; the HPCS System can still perform its intended function, however, it only has one source of power. In addition, the CTS 3.5.1 currently allows the HPCS System to be inoperable for up to 14 days for other reasons that will preclude it from performing its intended function. Since the NRC has previously approved the 14 day allowance for when the HPCS DG is inoperable, as well as when the HPCS System is inoperable for other reasons, this change is considered acceptable. In addition, this 14 day time for when HPCS is inoperable is also consistent with the Memorandum from R. L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975. B

L.23 The diesel generator accelerated test frequency requirements in CTS Table 4.8.1.1.2-1 and referenced in CTS 4.8.1.1.2.a are proposed to be deleted, leaving the ITS periodic Surveillance Frequency as 31 days in proposed SR 3.8.1.2 and SR 3.8.1.3. A plant procedure implements the C

TECHNICAL CHANGES - LESS RESTRICTIVE

L.23 (cont'd) requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger values specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG-1434, Rev. 1. In addition, Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Diesel Generators," allows Licensees to request removal from TS of provisions for accelerated testing. NMP2 also proposes to make the changes allowed by Generic Letter 94-01. The basis for removing the accelerated testing requirements from the Technical Specifications and modifying the Surveillance Frequency of CTS 4.8.1.1.2.a.4 and 5 (which are the test frequency specified in Table 4.8.1.1.2-1 as referenced in CTS 4.8.1.1.2.a), as stated in the Generic Letter, is for the licensee to commit to implement a maintenance program for monitoring and maintaining emergency diesel generator performance in accordance with the provisions of the maintenance rule and consistent with the guidance of Regulatory Guide 1.160. This commitment must be implemented within 90 days of issuance of the license amendment that removes the accelerated testing and special reporting requirements for emergency diesel generators from the Technical Specifications. NMP2 has already implemented a maintenance program for monitoring and maintaining emergency diesel generator performance in accordance with the provisions of the maintenance rule and consistent with the guidance of Regulatory Guide 1.160. Therefore, since the commitment has already been met, the requirements are not required to be in the ITS to provide adequate protection of the public health and safety and the allowances in Generic Letter 94-01 are acceptable. C

L.24 CTS 4.8.1.1.2.e.12 requires verification that the interval between each load block is within ± 10% of its design interval for Division 1 and 2 DGs. The SR is proposed to be changed in ITS SR 3.8.1.16 to delete the upper 10% limit, such that the interval between each load block is only required to be ≥ 90% of the design load interval.

As stated in the ISTS Bases, the purposes of the 10% load sequence time interval tolerance are to ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. The first purpose is met solely by the applying a lower limit. If the interval between two load blocks is greater than 110% of the design interval, the capability of the DG to perform its function is not necessarily impacted. For the first load interval, sufficient time after energizing the first load block to allow the DG to restore frequency and voltage prior to energizing the second load block is still provided, since the minimum time needed is the design interval minus 10%; allowing more time than the design interval plus 10% does not negatively affect C

TECHNICAL CHANGES - LESS RESTRICTIVE

L.24 (cont'd)

the ability of the DG to perform its intended function, with respect to the first load interval. In addition, it is recognized that if there is an additional load block following the first two described above, then allowing the load interval between the first two load blocks to be longer than the design interval plus 10% could impact the capability of the DG to restore frequency and voltage prior to the start of the third load block. However, the requirement that "each" load block be within the design load interval minus 10% will ensure that the time between the second and third load blocks is sufficient to ensure that the DG can restore frequency and voltage prior to energizing the third load block. The "each" requirement also ensures that all subsequent load intervals (e.g., the third, fourth, etc.) do not impact the capability of the DG to perform its intended function.

The second purpose described in the Bases for the ISTS SR is not related to the DG; it relates to the ability of the individual loads to perform their assumed functions. Thus, if a time delay was too long, while the individual load may be inoperable, the DG is not inoperable; the DG can still perform its intended function. Thus, the upper limit should not be considered as an operability requirement for the DG. If an individual load timer is too long, only the associated load should be considered inoperable. In addition, many of the load timers (the ones that affect the ECCS pumps) are required by ISTS 3.3.5.1, ECCS Instrumentation; thus the upper limits for these timers will be maintained in the ISTS.

A.1

ELECTRICAL POWER SYSTEMS

DC SOURCES

DC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

L.3

4.8.2.1.d.2 (Continued)

570 721 234 LA.3 C

a) Division I. Greater than or equal to 818 amperes during the initial 60 seconds; greater than or equal to 445 amperes during the next 118 minutes; and greater than or equal to 281 amperes during the remainder of the 2-hour test.

b) Division II. Greater than or equal to 570 amperes during the initial 60 seconds; greater than or equal to 449 amperes during the next 118 minutes; and greater than or equal to 305 amperes during the remainder of the 2-hour test.

c) Division III. Greater than or equal to 54.8 amperes during the initial 60 seconds; greater than or equal to 16.4 amperes during the remainder of the 2-hour test.

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SR 3.8.4.9

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

A.4 or modified performance discharge

Note 1 to SR 3.8.4.7

L.4

f. At least once per 12 months, during shutdown, performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating with capacity <100% of manufacturer's rating

A.4

SR 3.8.4.8

12 M.2 L.5

LA.4

Proposed 3rd Frequency

L.6

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
<4.8.1.1.2.a.5> <4.8.1.1.2.a.5 "#" Footnote>	SR 3.8.1.3 ----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by, and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. (7) (8) required Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load 2# (5450) kW and ≤ (5730) kW for Division 1 and 2 DGs, and ≥ (3308) kW and ≤ (3580) kW for Division 3 DG. (2) (4400) (3962) (2340) (2600)	As specified in Table 3.8.1-1 (31 days) (9)
<4.8.1.1.2.a.1>	SR 3.8.1.4 Verify each day tank (and engine mounted) (1) (tank) (1) contains ≥ (820) gal of fuel oil for Division 1 and 2 (2) and ≥ (820) gal for Division 3. (8) required (DG) (DGs) (3) (403) (2) (282)	31 days
<4.8.1.1.2.b>	SR 3.8.1.5 Check for and remove accumulated water from each day tank (and engine mounted tank). (1) (8) required	31 days (2)
<4.8.1.1.2.a.3>	SR 3.8.1.6 Verify (each required) (8) the fuel oil transfer (sub) (3) system operates to automatically transfer fuel oil from storage tank (8) to the day tank (and engine mounted tank). (1) (2) (11) (the)	92 days (62) (2)

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
<4.8.1.1.2.e.4> SR 3.8.1.~~7~~ 9 1	
<4.8.1.1.2.e.4 "***" Footnote> <4.8.1.1.2.e.4 "+" Footnote> <4.8.1.1.2.e.4 "*" Footnote> <4.8.1.1.2.e.4 "**" Footnote>	
----------NOTES----------	
1. All DG starts may be preceded by an engine prelube period.	
2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. TSTF-8 not adopted 12	
Verify on an actual or simulated loss of offsite power signal:	~~{18~~ months~~}~~ 24 2
a. De-energization of emergency buses;	
b. Load shedding from emergency buses; and for Divisions 1 and 2 only 17	
c. DG auto-starts from standby condition and:	
1. energizes permanently connected loads in ≤ ~~{10}~~ seconds, 13.20 2	
2. energizes auto-connected shutdown loads through ~~{~~automatic load sequencers~~}~~, the associated time delay relays 2 (for Division 1 and 2 DGs only 17)	
3. maintains steady state voltage ≥ ~~{3744}~~ 3950 V and ≤ ~~{4576}~~ 4370 V, 2	
4. maintains steady state frequency ≥ ~~{58.8}~~ Hz and ≤ ~~{61.2}~~ Hz, and	
5. supplies permanently connected and auto-connected shutdown loads for ≥ ~~{5}~~ minutes. for Division 1 and 2 DGs and supplies permanently connected shutdown loads for ≥ 5 minutes for Division 3 DG 17	

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.12 (10) <4.8.1.1.2.a.5> <DOC M.11>	
----------NOTES----------	
1. All DG starts may be preceded by an engine prelube period.	
2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR.	

Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and:	{18 months} 24
a. In ≤ {10} seconds after auto-start and during tests, achieves voltage ≥ {3744} V and ≤ [4576] V;	
b. In ≤ [10] seconds after auto-start and during tests, achieves frequency ≥ {58.8} Hz and ≤ {61.2} Hz;	
c. Operates for ≥ {5} minutes;	
d. Permanently connected loads remain energized from the offsite power system; and	
e. Emergency loads are energized [or] auto-connected through the automatic load sequencer to [from] the offsite power system.	

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
<4.8.1.1.2.e.11> SR 3.8.1.~~07~~ 15 NOTE This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. TSTF-8 not adopted 12 Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation~~;~~ and~~;~~ 2 2 b. Automatically energizing the emergency load from offsite power.	~~{18~~ 24 months~~}~~ 2
<4.8.1.1.2.e.12> SR 3.8.1.~~08~~ 16 NOTE This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. TSTF-8 not adopted 12 2 2 17 for the Division load 2 DGs only, Verify interval between each the sequenced load block is ~~within ± 10%~~ of design interval~~}~~ 2 ~~for each load sequencer timer~~.	~~{18~~ 24 months~~}~~ 2

automatic 2 time delay relay

≥90% 18

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.~~19~~ 17 <4.8.1.1.2.e.6> <4.8.1.1.2.a.6 "*" Footnote>	
----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. 12 TSTF-8 not adopted	
Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal:	24 2 {~~18~~ months}
a. De-energization of emergency buses;	
b. Load shedding from emergency buses; and 17 for Divisions 1 and 2 only	B
c. DG auto-starts from standby condition and:	
1. energizes permanently connected loads in ≤ {~~10~~} seconds, 17 for Divisions 1 and 2, 2	
2. energizes auto-connected emergency loads through the associated automatic time delay relays 2 load sequencers,	C
3. ~~achieves~~ 6 maintains steady state voltage ≥ {~~3744~~ 3950} V and ≤ {~~4576~~ 4370} V,	
4. ~~achieves~~ steady state frequency ≥ {58.8} Hz and ≤ {61.2} Hz, and	2
5. supplies permanently connected and auto-connected emergency loads for ≥ {5} minutes.	

(continued)

17 and for Divisions 3, energizes auto-connected emergency loads, C

16. Note 2 to ISTS SR 3.8.1.14 has been revised to permit performance of the 24-hour load test in MODES 1 and 2 in accordance with the requirements of the NMP2 Facility Operating License Amendment No. 64, dated March 7, 1995. This amendment allows performance of this test during power operation provided that the other remaining diesel generators are Operable.

17. While the NMP2 design for the Division 3 4.16 kV emergency bus includes a load shedding scheme, the loads are re-energized immediately upon restoration of power; the loads are not sequenced back onto the emergency buses through load timers. Thus, even if the loads are not shed, the DG will still operate and pick up loads when it re-energizes the emergency bus. In addition, the Division 3 DG does not have any auto-connected shutdown loads on a loss of offsite power. Therefore, ISTS SR 3.8.1.11, ISTS SR 3.8.1.12, and ISTS SR 3.8.1.19 have been modified to exclude these requirements for Division 3.

The maintaining of permanently connected loads energized from the offsite circuit is not required to be tested for the Division 3 4.16 kV emergency bus during the LOCA test. The NMP2 design for the Division 3 4.16 kV emergency bus does not include any additional permanently connected loads that are not adequately tested by ITS SR 3.8.1.9, the LOOP test, and ITS SR 3.8.1.17, the LOCA/LOOP test. The connection of the auto-connected emergency (LOCA) loads onto the Division 3 4.16 kV emergency bus is not dependent upon the source of the power supply to the 4.16 kV emergency bus. The emergency loads are connected in an identical manner, regardless of whether the power supply to the 4.16 kV emergency bus is the DG or an offsite circuit. The proper operation of the Division 3 auto-connected emergency loads is verified by ITS SR 3.8.1.17, the LOCA/LOOP test. Therefore, ISTS SR 3.8.1.12 has been modified to exclude these requirements for Division 3. In addition, there are no load timers for the Division 3 loads; the LOCA loads are automatically connected when the DG energizes the bus. Therefore, ISTS SR 3.8.1.19 has been modified to exclude this requirement. B C

The NMP2 design for the Division 3 4.16 kV emergency bus only includes one major load block, the HPCS pump. Therefore, ISTS SR 3.8.1.18 has been modified to exclude this requirement for Division 3. B

These changes are consistent with current licensing basis, which does not include these requirements in the CTS.

18. ISTS SR 3.8.1.18 requires verification that the interval between each sequenced load block is within ± 10% of design interval for each load sequence timer. The SR is proposed to be changed to delete the upper 10% limit, such that the interval between each load block is only required to be ≥ 90% of the design load interval. C

As stated in the ISTS Bases, the purposes of the 10% load sequence time interval tolerance are to ensure that sufficient time exists for the DG to restore frequency and

18. (continued)

voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. The first purpose is met solely by the applying a lower limit. If the interval between two load blocks is greater than 110% of the design interval, the capability of the DG to perform its function is not necessarily impacted. For the first load interval, sufficient time after energizing the first load block to allow the DG to restore frequency and voltage prior to energizing the second load block is still provided, since the minimum time needed is the design interval minus 10%; allowing more time than the design interval plus 10% does not negatively affect the ability of the DG to perform its intended function, with respect to the first load interval. In addition, it is recognized that if there is an additional load block following the first two described above, then allowing the load interval between the first two load blocks to be longer than the design interval plus 10% could impact the capability of the DG to restore frequency and voltage prior to the start of the third load block. However, the requirement that "each" load block be within the design load interval minus 10% will ensure that the time between the second and third load blocks is sufficient to ensure that the DG can restore frequency and voltage prior to energizing the third load block. The "each" requirement also ensures that all subsequent load intervals (e.g., the third, fourth, etc.) do not impact the capability of the DG to perform its intended function.

The second purpose described in the Bases for the SR is not related to the DG; it relates to the ability of the individual loads to perform their assumed functions. Thus, if a time delay was too long, while the individual load may be inoperable, the DG is not inoperable; the DG can still perform its intended function. Thus, the upper limit should not be considered as an operability requirement for the DG. If an individual load timer is too long, only the associated load should be considered inoperable. In addition, many of the load timers (the ones that affect the ECCS pumps) are required by ISTS 3.3.5.1, ECCS Instrumentation; thus the upper limits for these timers will be maintained in the ISTS.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

Two fuel oil transfer pumps per DG are required since each pump only has a simplex strainer (1)

system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

is conservative with respect (2)

(3) (1) (16)

The Frequency for this SR is variable, depending on individual system design, with up to a 92 day interval. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 18); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day [and engine mounted] tanks during or following DG testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs.

(4) SR 3.8.1.7

See SR 3.8.1.2

(6)

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The [18 month] Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.~~14~~ 12

Consistent with

Regulatory Guide 1.~~108~~ 9 (Ref. ~~9~~ 11), paragraph ~~C.2.a.(3)~~ C.2.2.9, requires demonstration ~~once per 18 months~~ that the DGs can start and run continuously at full load capability for an interval of ~~not less than 24 hours~~ 22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG and 2 hours of which is at a load equivalent to 105% to 110% of the continuous ~~duty~~ rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.91 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. ~~using a power factor ≤ [0.9]~~. This power factor is ~~chosen to be~~ representative of the actual design basis inductive loading that the DG could experience.

The ~~[18 months]~~ 24 months Frequency is consistent with the ~~recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3),~~ takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by ~~two~~ three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. <INSERT SR 3.8.1.12>

TSTF-8 not adopted

However, it is acceptable to perform this SR in MODES 1 and 2 provided the other two DGs are OPERABLE, since a perturbation can only affect one division or DG. If during performance of this Surveillance one of the other DGs becomes inoperable, this Surveillance is to be suspended.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.18

Under accident conditions [and loss of offsite power] loads are sequentially connected to the bus by the [load sequencing] [power]. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The [100%] load sequence time interval [tolerance] ensures that [sufficient] time exists for the DG to restore frequency and voltage prior to applying the next load [and that safety analysis assumptions regarding ESF equipment time delays are not violated]. [Reference 2 provides a summary of the automatic loading of [ESF] buses.]

The Frequency of [18 months] [is consistant with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2)] takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

> Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:
>
> a. Performance of the SR will not render any safety system or component inoperable;

(continued)

7 INSERT SR 3.8.1.16

There is no upper limit for the load sequence time interval since, for a single load interval (i.e., the time between two load blocks), the capability of the DG to restore frequency and voltage prior to applying the second load is not negatively affected by a longer than designed load interval, and if there are additional load blocks (i.e., the design includes multiple load intervals), then the lower limit requirements (-10%) will ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the remaining load blocks (i.e., all load intervals must be ≥ 90% of the design interval).

C

BASES

ACTIONS

A.1 (continued)

remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit, and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. The potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.12, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to

(continued)

INSERT TABLE B 3.8.8-1

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a]	DIVISION 3[a]
AC buses	4160 V	Switchgear 2ENS*SWG101	Switchgear 2ENS*SWG103	Switchgear 2ENS*SWG102
	600V	Load Center 2EJS*US1 MCCs 2EHS*MCC101, 2EHS*MCC102, and 2EHS*MCC103 Distribution Panels 2EJS*PNL100A and 2LAC*PNL100A	Load Center 2EJS*US3 MCCs 2EHS*MCC301, 2EHS*MCC302, and 2EHS*MCC303 Distribution Panels 2EJS*PNL300B and 2LAC*PNL300B	MCC 2EHS*MCC201
	240/120 V			Distribution Panel 2SCV*PNL200P
	208/120 V			Distribution Panel 2LAC*PNLE03
DC buses	125 V	Switchgear 2BYS*SWG002A MCC 2DMS*MCCA1 Distribution Panels 2BYS*PNL201A, 2BYS*PNL202A, and 2BYS*PNL204A	Switchgear 2BYS*SWG002B MCC 2DMS*MCCB1 Distribution Panels 2BYS*PNL201B, 2BYS*PNL202B, and 2BYS*PNL204B	Distribution Panel 2CES*IPNL414
120 VAC uninter-ruptible panels	120 V	Distribution Panels 2VBS*PNL101A and 2VBS*PNL102A	Distribution Panels 2VBS*PNL301B and 2VBS*PNL302B	

L.6 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The diesel generators are not assumed to be an initiator of any analyzed event. The diesel generators function to mitigate consequences of an analyzed event by supplying sufficient power to equipment assumed to function during an accident. The diesel generator day tank fuel oil and fuel oil transfer pumps requirements support operation of the diesel generators and therefore, help mitigate the consequences of design basis accidents. The proposed change still provides assurance diesel generator day tank fuel oil level requirements will be maintained and more frequent diesel generator testing will not adversely impact diesel generator day tank fuel oil level since the day tanks are designed to hold approximately 1 hour (for Division 1 and 2 DGs) and 2 hours (for Division 3 DG) of fuel oil prior to reaching the day tank level limit. Additionally, low level alarms and plant practices provide assurance that day tank fuel oil level is maintained within required limits. The auto start of the fuel oil transfer pump also occurs at approximately this point. The 62 day fuel oil transfer pump frequency is also conservative with respect to the ASME Section XI requirements for similar pumps. Also, Surveillances of these pumps routinely show that the pumps are OPERABLE. Therefore, this proposed change will not involve a significant increase in the probability or consequences of an accident previously evaluated. 1 C

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   No significant reduction in a margin of safety is involved with this change since the 31 day Frequency has been shown, based on operating experience, to be adequate for maintaining day tank fuel oil level. Additionally, low level alarms and plant practices provide additional assurance that day tank fuel oil level is maintained within required limits. The 62 day fuel oil transfer pump frequency has been shown, based on operating experience of other ASME Section XI tested pumps, to be adequate for demonstrating OPERABILITY of the pumps. 1 C

L.23 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The diesel generators (DGs) are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. As such, deletion of the accelerated test frequency requirements will not increase the probability of any accident previously evaluated. The proposed ITS continues to require periodic testing of the DGs, and, in combination with the accelerated testing requirements in plant procedures provides adequate assurance of OPERABLE DGs and therefore, does not involve an increase in the consequences of any accident previously evaluated.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the OPERABILITY of the DGs is determined in the same manner, and periodic testing and accelerated testing, if necessary, will continue to be performed. Therefore, the proposed change continues to provide assurance of the capability of the DGs to perform their safety function.

L.24 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The diesel generators (DGs) are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. As such, the deletion of the upper limit will not increase the probability of any accident previously evaluated. If the interval between two load blocks is greater than 110% of the design interval, the capability of the DG to perform its function is not necessarily impacted. For the first load interval, sufficient time after energizing the first load block to allow the DG to restore frequency and voltage prior to energizing the second load block is still provided, since the minimum time needed is the design interval minus 10%; allowing more time than the design interval plus 10% does not negatively affect the ability of the DG to perform its intended function, with respect to the first load interval. In addition, it is recognized that if there is an additional load block following the first two described above, then allowing the load interval between the first two load blocks to be longer than the design interval plus 10% could impact the capability of the DG to restore frequency and voltage prior to the start of the third load block. However, the requirement that "each" load block be within the design load interval minus 10% will ensure that the time between the second and third load blocks is sufficient to ensure that the DG can restore frequency and voltage prior to energizing the third load block. The "each" requirement also ensures that all subsequent load intervals (e.g., the third, fourth, etc.) do not impact the capability of the DG to perform its intended function. Therefore, the change does not involve any increase to the consequences of any accident previously evaluated. C

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the OPERABILITY of the DG continues to be determined based on its capability to perform its safety related function.

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and: C

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems described in (b.1) and (b.2) above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system. C

5.5.12 10 CFR 50 Appendix J Testing Program Plan

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B with the exemptions stated in

(continued)

5.5 Programs and Manuals

5.5.12 10 CFR 50 Appendix J Testing Program Plan (continued)

Section 2.D(ii) of the Operating License. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, entitled, "Performance-Based Containment Leak-Test Program," dated September 1995 with the following exceptions:

1. The measured leakage of main steam isolation valves (MSIVs) is excluded from the combined leakage rate of 0.6 L_a, and as-found testing is not required to be performed on the MSIVs.

2. Primary containment air lock door seals are tested prior to re-establishing primary containment OPERABILITY when something has been done that would bring into question the validity of the previous air lock door seal test.

b. The peak calculated containment internal pressure (P_a) for the design basis loss of coolant accident is 39.75 psig.

c. The maximum allowable primary containment leakage rate (L_a) at P_a shall be 1.1% of primary containment air weight per day.

d. Leakage Rate acceptance criteria are:

1. Primary Containment leakage rate acceptance criterion is < 1.0 L_a. The combined leakage rate for Type B and C tests on a minimum pathway basis, except for main steam line isolation valves and Primary Containment isolation valves which are hydrostatically tested, is < 0.6 L_a.

   During the first unit startup following testing in accordance with this program, the as-left combined leakage rate acceptance criteria are < 0.6 L_a for the Type B and C tests on a maximum pathway basis, except for main steam line isolation valves and Primary Containment isolation valves which are hydrostatically tested, and ≤ 0.75 L_a for Type A tests.

2. Air lock testing acceptance criteria are:

   (a) Overall air lock leakage rate is ≤ 0.05 L_a when tested at greater than or equal to P_a; and

(continued)

5.5 Programs and Manuals

5.5.12 <u>10 CFR 50 Appendix J Testing Program Plan</u> (continued)

(b) For each door, leakage rate is ≤ 5 scfh when the gap between the door seals is pressurized to ≥ 10 psig.

e. The provisions of SR 3.0.3 are applicable to the 10 CFR 50 Appendix J Testing Program Plan.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

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

5.6.1 Occupational Radiation Exposure Report

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors), for whom monitoring was performed, receiving an annual deep dose equivalent of > 100 mrems and the associated collective deep dose equivalent (reported in man-rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket ion chamber, thermoluminescent dosimeter (TLD), electronic dosimeter, or film badge measurements. Small exposures totalling < 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources should be assigned to specific major work functions. The report shall be submitted by April 30 of each year.

5.6.2 Annual Radiological Environmental Operating Report

----------NOTE----------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

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

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

----------NOTE----------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit shall be submitted in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and the Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the safety/relief valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

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

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

1. The APLHGR for Specification 3.2.1.

2. The MCPR for Specification 3.2.2.

3. The LHGR for Specification 3.2.3.

4. Control Rod Block Instrumentation Setpoint for the Rod Block Monitor—Upscale Function Allowable Value for Specification 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel," U.S. Supplement, (NRC approved version specified in the COLR).

2. NEDE-23785-1-PA, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," (NRC approved version specified in the COLR).

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

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

5.6.6 Post Accident Monitoring (PAM) Instrumentation Report

When a report is required by Condition B or F of LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

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

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation)

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

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

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

d. Each individual or group entering such an area shall possess at least one of the following:

1. A radiation monitoring device that continuously displays radiation dose rates in the area ("radiation monitoring and indicating device").

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached ("alarming dosimeter"), with an appropriate alarm setpoint.

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

(continued)

5.7 High Radiation Area

5.7.1 <u>High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation)</u> (continued)

4. A self-reading dosimeter and,

   (a) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual at the work site, qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel radiation exposure within the area, or

   (b) Be under the surveillance, as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

5.7.2 <u>High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation)</u>

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

   1. All such door and gate keys shall be maintained under the administrative control of the Station Shift Supervisor - Nuclear or a designee, or the radiation protection manager or a designee; and

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

(continued)

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation) (continued)

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

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

d. Each individual (whether alone or in a group) entering such an area shall possess at least one of the following:

1. An alarming dosimeter with an appropriate alarm setpoint.

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

3. A self-reading dosimeter and,

(a) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel exposure within the area, or

(continued)

5.7 High Radiation Area

5.7.2 <u>High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation)</u> (continued)

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

4. A radiation monitoring and indicating device in those cases where the options of Specifications 5.7.2.d.2 and 5.7.2.d.3, above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

f. Such individual areas that are within a larger area that is controlled as a high radiation area, where no enclosure exists for purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, but shall be barricaded and conspicuously posted as a high radiation area, and a conspicuous, clearly visible flashing light shall be activated at the area as a warning device.

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5.5 Programs and Manuals

<DOC M.1> 5.5.10 Technical Specifications (TS) Bases Control Program (continued)

prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.11 Safety Function Determination Program (SFDP)

<DOC M.1>

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. 1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

TSTF-273 and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s),

(continued)

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5.5 Programs and Manuals

<DOC M.1>

5.5.12 Safety Function Determination Program (SFDP) (continued)

A required system redundant to support system(s) for the supported systems [a] and [b] above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

INSERT 5.5.12

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When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

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