# CATEGORY 1

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9612260193 DOC.DATE: 96/12/12 NOTARIZED: NO DOCKET #
FACIL:50-397 WPPSS Nuclear Project, Unit 2, Washington Public Powe 05000397
AUTH.NAME AUTHOR AFFILIATION
EMIS,P.R. Washington Public Power Supply System
RECIP.NAME RECIPIENT AFFILIATION
Document Control Branch (Document Control Desk)

See Proposed changes to T/S

SUBJECT: Submits proposed mod to amend requests Revs A & B re overall conversion of current TS to improved TS based upon NUREG-1434,rev 1.

DISTRIBUTION CODE: A001D COPIES RECEIVED:LTR 1 ENCL 1 SIZE: 65+900
TITLE: OR Submittal: General Distribution

NOTES:

| | RECIPIENT ID CODE/NAME | COPIES LTTR | COPIES ENCL | RECIPIENT ID CODE/NAME | COPIES LTTR | COPIES ENCL |
|---|---|---|---|---|---|---|
| | PD4-2 LA | 1 | 1 | PD4-2 PD | 1 | 1 |
| | COLBURN,T | 1 | 1 | | | |
| INTERNAL: | ACRS | 1 | 1 | FILE CENTER 01 | 1 | 1 |
| | NRR/DE/ECGB/A | 1 | 1 | NRR/DE/EMCB | 1 | 1 |
| | NRR/DRCH/HICB | 1 | 1 | NRR/DSSA/SPLB | 1 | 1 |
| | NRR/DSSA/SRXB | 1 | 1 | NUDOCS-ABSTRACT | 1 | 1 |
| | OGC/HDS3 | 1 | 0 | | | |
| EXTERNAL: | NOAC | 1 | 1 | NRC PDR | 1 | 1 |

C A T E G O R Y 1 D O C U M E N T

NOTE TO ALL "RIDS" RECIPIENTS:
PLEASE HELP US TO REDUCE WASTE! CONTACT THE DOCUMENT CONTROL DESK, ROOM OWFN 5D-5(EXT. 415-2083) TO ELIMINATE YOUR NAME FROM DISTRIBUTION LISTS FOR DOCUMENTS YOU DON'T NEED!

TOTAL NUMBER OF COPIES REQUIRED: LTTR 14 ENCL 13

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
*P.O. Box 968 • Richland, Washington 99352-0968*

December 12, 1996
GO2-96-241

Docket No. 50-397

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

Gentlemen:

Subject: **WNP-2, OPERATING LICENSE NPF-21**
**REQUEST FOR AMENDMENT TO TECHNICAL SPECIFICATIONS**

References:
1) Letter dated December 8, 1995, GO2-95-265, JV Parrish (SS) to NRC, "Request for Amendment to Technical Specifications"

2) Letter dated July 9, 1996, GO2-96-132, PR Bemis (SS) to NRC "Request for Amendment to Technical Specifications"

3) Letter dated July 26, 1996, GI2-96-189, TV Wambach (NRC) to JV Parrish (SS), "Draft Safety Evaluation of Proposed Improved Technical Specifications, Washington Public Power Supply System Nuclear Project No. 2 (TAC NO. M94226)"

4) Letter dated August 30, 1996, GO2-96-172, PR Bemis (SS) to NRC "Comments on Draft Safety Evaluation of Proposed Improved Technical Specifications"

5) Letter dated June 3, 1996, GI2-96-137, TG Colburn (NRR) to JV Parrish (SS) "Issuance of Amendment for the Washington Public Power Supply System Nuclear Project No. 2 (TAC NO. M93949)"

In accordance with the Code of Federal Regulations, Title 10, Parts 50.90 and 2.101, the Supply System hereby submits a revised request for amendment to the WNP-2 Technical Specifications and Operating License. This letter proposes a modification to the amendment requests previously submitted in Reference 1 (Revision A) and Reference 2 (Revision B).

A001

In those references, the Supply System requested an overall conversion of the WNP-2 current Technical Specifications (CTS) to the improved Technical Specifications (ITS), based upon NUREG-1434, Revision 1, "Standard Technical Specifications, General Electric Plants, BWR/6," (STS). The Supply System has concluded that this proposed revision does not change the "No Significant Hazards Considerations" or the "Environmental Assessment" conclusions for Revisions A or B.

The revised request consists of this transmittal letter and six attachments. The specific changes are listed in Attachment 1, "Summary of Changes." Included in this attachment is a brief summary of each change and the sections impacted. The page insert and removal instructions are contained in Attachment 2, "Insert and Discard Instructions," to facilitate updating the submittal. In Attachment 3, "Revision C," the specific changes are annotated by a vertical bar and a "C" in the right margin. The remaining attachments pertain to three specific issues and are addressed separately in this letter.

In response to the staff's draft safety evaluation of the WNP-2 proposed conversion to ITS (Reference 3), the Supply System provided comments and summarized the outstanding issues and proposed changes (Attachment 4). In this revision, Supply System actions proposed in the attachment and those that were agreed upon during subsequent discussions with the staff have been incorporated.

For ease of reference and clarification purposes, three issues pertaining to control of relocated requirements, testing the emergency diesel generators, and response time testing are also addressed in further detail as follows.

Relocated Requirements

In August 1996, the Nuclear Energy Institute (NEI) issued NEI 96-06, "Improved Technical Specifications Conversion Guidance." On October 9, 1996, the NRC issued Administrative Letter (AL) 96-04, "Efficient Adoption of Improved Technical Specifications." These two documents provide guidance on the relocation of requirements to documents other than the FSAR or the Bases. Of specific concern was the process to be used by the licensee to control changes to documents following implementation.

The Supply System has referenced these documents in the resolution of issues related to relocation of requirements proposed in the ITS submittal. In Revisions A and B, it was requested that specific requirements be relocated to the Licensee Controlled Specifications (LCS), plant controlled documents or plant procedures subject to control by the provisions of 10 CFR 50.59. In AL 96-04 and NEI 96-06, guidance was provided that only FSAR changes are subject to 10 CFR 50.59. Therefore, no credit should be taken in the submittal for 10 CFR 50.59 control of other documents. Accordingly, the following changes are proposed:

1. Requests for relocations to plant controlled documents are deleted and the document in which the requirement will be placed has been specified.

2. The LCS has been incorporated into the WNP-2 FSAR to assure that the document is subject to the provisions of 10 CFR 50.59.

3. Attachment 4, "Relocated Items and Control Process," supersedes Enclosure 3 of Reference 2. This attachment contains a list of the relocated requirements, the proposed new location and the process under which changes will be controlled.

4. As stated above, AL 96-04 clarifies relocated requirements option for control by 10 CFR 50.59, and recommends relocation to the FSAR or Bases. Therefore, all previously proposed relocations to plant procedures have been changed to the FSAR or LCS Manual, and Enclosure 4 of Reference 2 is superseded by Attachment 4, "Relocated Items and Control Process." As part of a planned FSAR improvement initiative, changes to these relocated requirements may be made but any such changes will be evaluated pursuant to the requirements of 10 CFR 50.59.

Diesel Generator Testing

In Reference 4, the Supply System indicated that Revision C would not include the requirement that the Diesel Generators be tested at the power factor specified in the Bases of the original submittal. Following further discussions between the Supply System and the staff, it was agreed that the surveillances will require that the Diesel Generators be tested as close as practicable to the accident load power factor that is specified in the Bases, within the limitations of the excitation system.

Further discussions of the capabilities of the installed equipment, the justification for the reactive load range and excitation current limitations, and problems expected if testing were conducted at the accident load power factor are contained in Attachment 5, "Diesel Generator Testing Results and Evaluation."

Response Time Testing

In August 1996, questions concerning the Supply System implementation of changes to the method used to verify response times were raised by the staff and resulted in an inspection. Inspection Report 96-22 results have not been transmitted to the Supply System. The Supply System implemented guidance provided in NEDO 32291 under the provisions of 10 CFR 50.59. The changes proposed in the ITS submittal, based on the guidance in NEDO 32291, were characterized as "administrative" since the Supply

System believes that the same changes implemented in CTS are acceptable upon implementation of ITS. Because the issue has the potential to impact CTS as well as ITS, the Supply System is withdrawing the proposed changes based on the guidance in NEDO 32291 submitted in Reference 1 relative to response time testing, pending resolution of this issue. (Proposed changes to response time testing based on other considerations as described in the applicable discussion of changes for 3.3.1.1, 3.3.5.1, 3.3.6.1, and 3.3.6.2, provided in Attachment 3, are not affected).

Two new issues were also identified by the Supply System and pertain to a request to extend the surveillance interval for the RWCU isolation function added in Amendment 147, and a change to the allowable values for the time delay relay functions added to Section 3.3.8.1. Further details are contained in the Discussion of Changes (DOC) for 3.3.6.1, LE.1 and DOC for 3.3.8.1, M.3 (provided in Attachment 3).

Additional review comments have been provided by the staff following receipt of the draft safety evaluation. Based on discussions between the staff and the Supply System, many of the comments have lead to the changes that were incorporated into Revision C. The staff has also requested that each reference to the Final Policy Statement of July 1995 be changed to reference the rule making pertaining to 10 CFR 50.36. This requested change has not been incorporated into Revision C but will be included in the final copy of the Bases that will be provided to the staff in the near future.

The conversion to ITS will have an impact on the surveillance requirement testing program at WNP-2. In the conversion to ITS, the Supply System will also be implementing a 24-month maintenance cycle by extending certain surveillance intervals from 18 months to 24 months. Other surveillance requirement intervals were also extended. Upon implementation, those extended surveillance intervals will be assigned a new due date based upon the date of last performance and the new interval.

There are also new surveillance requirements in the ITS. For instance, if a test is currently performed at WNP-2 and it is outside of the Technical Specification Surveillance Program, a new due date will be established based on the date the test was last performed. If the test is a new test, the Supply System will assign a due date based upon the ITS implementation date, plus the surveillance interval. All changes to surveillance test requirements that are not related to surveillance intervals changes will also be considered to be met upon implementation, with the change in the test to be implemented during the next scheduled performance of the surveillance.

In closing, we have previously indicated that implementation of the ITS was expected in the fourth quarter of 1996. However, based upon an expected receipt of the Safety Evaluation of the proposed ITS conversion in January 1997, implementation of ITS will be delayed. The exact date of conversion will be provided to the staff at a later date. As such, the Supply System requests that the ITS be issued with an implementation date no later than June 30, 1997.

Should you have any questions or require additional information pertaining to this letter, please contact either me or D.A. Swank at (509) 377-4563.

Respectfully,

P.R. Bemis
Vice President, Nuclear Operations
Mail Drop PE23

MEG

Attachment 1: Summary of Changes
Attachment 2: Insert and Discard Instructions
Attachment 3: Revision C
Attachment 4: Relocated Items and Control Process
Attachment 5: Diesel Generator Testing Results and Evaluation

cc: LJ Callan - NRC RIV
KE Perkins, Jr. - NRC RIV, Walnut Creek Field Office
NS Reynolds - Winston & Strawn
TG Colburn - NRR
DL Williams - BPA MD 399
NRC Sr. Resident Inspector - MD 927N

## SUMMARY OF CHANGES

This enclosure was prepared to provide a brief summary of the changes in Revision C. The original Technical Specification amendment request was submitted to the NRC on December 8, 1995, and Revision B was submitted to the NRC on July 9, 1996.

The order in which summary of the changes are listed is of no significance. Replacement pages have been provided for each of the pages affected by Revision C changes. Page insert and removal instructions have also been provided to facilitate updating the amendment request to include Revision C.

1. Specification 5.6.5, Core Operating Limits Report, page 5.0-21, Bases pages B 2.0-2, B 2.0-3, B 2.0-4, B 2.0-5, B 3.1-35, B 3.1-36, B 3.1-38, B 3.1-39, B 3.2-1, B 3.2-3, B 3.2-4, B 3.2-5, B 3.2-7, B 3.2-8, B 3.2-9, B 3.2-10, B 3.3-2, B 3.3-3, B 3.3-4, B 3.3-5, B 3.3-10, B 3.3-11, B 3.3-12, B 3.3-13, B 3.3-16, B 3.3-20, B 3.3-21, B 3.3-24, B 3.3-25, B 3.3-26, B 3.3-28, B 3.3-30, B 3.3-31, B 3.3-43, B 3.3-44, B 3.3-45, B 3.3-48, B 3.3-49, B 3.3-51, B 3.3-52, B 3.3-78, B 3.3-83, B 3.3-84, B 3.3-85, B 3.3-86, B 3.3-102, B 3.3-104, B 3.3-107, B 3.3-108, B 3.3-110, B 3.3-111, B 3.3-113, B 3.3-115, B 3.3-116, B 3.3-117, B 3.3-118, B 3.3-121, B 3.3-123, B 3.3-124, B 3.3-125, B 3.3-127, B 3.3-128, B 3.3-129, B 3.3-130, B 3.3-130, B 3.3-131, B 3.3-132, B 3.4-2, B 3.4-3, B 3.4-4, B 3.4-5, B 3.4-9, B 3.4-10, B 3.4-17, B 3.4-18, B 3.4-19, B 3.4-20, B 3.4-21, B 3.4-22, and B 3.4-24, CTS markup for Specification 4.0, pages 1 of 8 through 8 of 8, and Discussion of Changes A.2 and LA.3 (deleted) to ITS Chapter 4.0 (page 1).

   New reference documents have been provided for the COLR and Discussion of Changes A.2 and LA.3 to ITS Chapter 4.0 has been deleted. This change reflects the receipt of Amendment 146 to the WNP-2 CTS. One of the new references added per Amendment 146 (CTS 6.9.3.2.11) has been changed to reflect the version that includes the NRC SER. The only difference between the current Technical Specification version (dated May 24, 1996) and the one proposed by this change (dated July 1996) is the inclusion of the NRC SER. In addition, due to the changes to the COLR references, numerous references in the Bases have been changed to reflect the new fuel vendor references.

   Corresponding changes have also been made to the Discussion of Changes LA.4 to ITS 3.4.1 (page 4), to the CTS markup for Specification 5.6, page 7 of 9, to the Discussion of Changes A.8 (new) to ITS 5.6 (page 2), to the NUREG-1434 ITS markup, insert page 5.0-20, and to the NUREG-1434 Bases markup, pages B 2.0-3, B 2.0-5, B 2.0-6, B 2.0-7, B 3.1-33, B 3.1-34, B 3.1-36, B 3.1-37, B 3.2-1, B 3.2-2, Insert Page B 3.2-2, Insert Page B 3.2-4, B 3.2-5, B 3.2-6, B 3.2-8, Insert page B 3.2-8, B 3.2-9, B 3.2-10, B 3.2-11, Insert Page B 3.2-11, B 3.3-2, B 3.3-3, B 3.3-5, B 3.3-9, B 3.3-10, B 3.3-11, B 3.3-13, B 3.3-15, B 3.3-20, B 3.3-21, B 3.3-24, B 3.3-26, B 3.3-27, B 3.3-28, B 3.3-31,

## SUMMARY OF CHANGES

1. (continued)

B 3.3-32, Insert Page B 3.3-52c, Insert Page B 3.3-52d, Insert Page B 3.3-52e, Insert Page B 3.3-52f, Insert Page B 3.3-52i, Insert Page B 3.3-52j, Insert Page B 3.3-52m, Insert Page B 3.3-52n, B 3.3-72, B 3.3-78, B 3.3-80, B 3.3-81, B 3.3-98, B 3.3-99, B 3.3-102, B 3.3-103, B 3.3-104, B 3.3-106, B 3.3-109, B 3.3-110, B 3.3-111, B 3.3-113, Insert Page B 3.3-113, B 3.3-117, B 3.3-119, B 3.3-120, B 3.3-121, B 3.3-123, B 3.3-124, B 3.3-125, B 3.3-126, B 3.3-128, B 3.4-2, Insert Page B 3.4-3, B 3.4-4, B 3.4-6, Insert Page B 3.4-6, B 3.4-17, B 3.4-21, Insert Page B 3.4-21, Insert Page B 3.4-21b, and Insert Page B 3.4-21g.

2. Specification 3.3.4.2, ATWS-RPT Instrumentation, ACTION A, pages 3.3-33 and B 3.3-91.

The time provided to restore a single ATWS-RPT channel has been reduced from the 14 days to 7 days, as requested by the NRC reviewer (comment 54 and 55).

Corresponding changes have also been made to the CTS markup for ITS 3.3.4.2, pages 1 of 4 and 3 of 4, to the Discussion of Changes M.1 to ITS 3.3.4.2 (page 1), to the NUREG-1434 ITS markup, page 3.3-31, to the Justification for Deviations to Chapter 3.3, comment number 45 (page 8), and to the NUREG-1434 Bases markup, page B 3.3-86.

3. Specification 3.3.8.2, RPS Electric Power Monitoring, SR 3.3.8.2.2 and SR 3.3.8.2.3, pages 3.3-74, B 3.3-220, and B 3.3-221.

The Allowable Values for the time delays for both the normal and alternate sources have been changed to 3.46 seconds. This new value is based on the most recent setpoint calculations. Since the two sources now have the same time delay settings, the calibration SRs (SR 3.3.8.2.2 and SR 3.3.8.2.3) have been combined into one SR, consistent with NUREG-1434.

Corresponding changes have also been made to the CTS markup for ITS 3.3.8.2, page 1 of 1, to the Discussion of Changes M.3 to ITS 3.3.8.2 (page 1), to the NUREG-1434 ITS markup, pages 3.3-85 and insert page 3.3-85, and to the NUREG-1434 Bases markup, pages B 3.3-245 and B 3.3-246.

4. Specification 3.5.1, ECCS-Operating, ACTIONS A and C, pages 3.5-1, 3.5-2, B 3.5-5, B 3.5-6, B 3.5-7, B 3.5-8, B 3.5-13, B 3.5-14; Specification 3.7.1, SW System and UHS, ACTION B, pages 3.7-2 and B 3.7-4; Specification 3.8.1, AC Sources-Operating, ACTIONS A, B, and E, pages 3.8-2, 3.8-3,3.8-5, B 3.8-8, B 3.8-11, B 3.8-12,

## SUMMARY OF CHANGES

4. (continued)

B 3.8-15, B 3.8-16, B 3.8-18 through B 3.8-25, B 3.8-27, and B 3.8-29 through B 3.8-33; and Specification 3.8.2, AC Sources-Shutdown, pages 3.8-21 and B 3.8-39.

The extended outage times based on the GE-NE-A0005809-01 reliability study have been deleted and replaced with the current times provided in the CTS or by the NUREG, as applicable. This change was requested by the NRC since there was insufficient time to review the proposed change during the ITS review process. In addition, due to this change, Bases references to the reliability study have been deleted and all other references renumbered, as appropriate.

Corresponding changes have also been made to the CTS markup for ITS 3.5.1, pages 2 of 6 and 3 of 6, to the Discussion of Changes L.3 and L.5 to ITS 3.5.1 (page 5), to the CTS markup for ITS 3.7.1, page 1 of 3, to the Discussion of Changes L.1 to ITS 3.7.1 (page 3), to the CTS markup for ITS 3.8.1, pages 1 of 9 and 2 of 9, to the Discussion of Changes L.3 and L.4 to ITS 3.8.1 (pages 9 and 10 ), to the CTS markup for ITS 3.8.2, page 1 of 1, to the Discussion of Changes L.1 to ITS 3.8.2 (page 3), to the NSHE for ITS 3.5.1, L.3, pages 3 and 4, to the NSHE for ITS 3.7.1, L.1, pages 1 and 2, to the NSHE for ITS 3.8.1, L.3, pages 3 and 4, to the NSHE for ITS 3.8.2, L.1, pages 1 and 2, to the NUREG-1434 ITS markup, pages 3.5-1 and 3.5-2, to the Justification for Deviations to Section 3.3, comment number 2 (page 1), to the NUREG-1434 ITS markup, page 3.7-2, to the Justification for Deviations to Section 3.7, comment number 6 (page 1), to the NUREG-1434 ITS markup, pages 3.8-2, 3.8-3, 3.8-5, and 3.8-22, to the Justifications for Deviation to Section 3.8, comment number 4 (page 1), to the NUREG-1434 Bases markup, pages B 3.5-5, B 3.5-6, B 3.5-7, B 3.5-8, B 3.5-13, Insert page B 3.5-13, B 3.7-4, B 3.8-7, B 3.8-10, B 3.8-14, B 3.8-15, Insert page B 3.8-16, B 3.8-17 through B 3.8-21, B 3.8-23 through B 3.8-26, B 3.8-28 through B 3.8-30, B 3.8-32 through B 3.8-34, and B 3.8-40.

5. Bases 3.8.4, DC Sources-Operating, page B 3.8-57.

The 100% load ratings of the battery chargers has been added to the Bases. These values are the current values in the CTS. This will ensure that proper controls over the design load ratings of the battery changers are maintained. This change was requested by the NRC reviewer.

Corresponding changes have also been made to the Discussion of Changes LA.4 to ITS 3.8.4 (pages 2 and 3), and to the NUREG-1434 Bases markup, pages B 3.9-57 and Insert page B 3.8-57.

## SUMMARY OF CHANGES

6. Specification 1.0, PTLR Definition, page 1.1-6; Specification 3.3.3.1, PAM Instrumentation, ACTIONS B and F, pages 3.3-23, 3.3-24 B 3.3-67 and B 3.3-68; Specification 3.4.12, RCS P/T Limits, LCO and Surveillance Requirements, pages 3.4-25 through 3.4-29, new pages 3.4-30, 3.4-31, and B 3.4-32, B 3.4-57 through B 3.4-59, and B 3.4-62 through B 3.4-66; and Specification 5.6.6 PTLR (deleted), page 5.0-22.

   The PTLR has been deleted and the actual limits (consistent with the CTS limits) have been added into the ITS.

   Corresponding changes have also been made to the CTS markup for ITS Chapter 1.0, pages 1 of 19 through 19 of 19, to the Discussion of Changes A.17 to ITS Chapter 1.0 (page 5), to the CTS markup for ITS 3.3.3.1, page 4 of 6, to the Discussion of Changes A.6, LA.1, and L.2 to ITS 3.3.3.1 (pages 2, 3 and 9), to the CTS markup for ITS 3.4.12, pages 1 of 7 through 7 of 7, to the Discussion of Changes A.7, A.8, and LA.1 to ITS 3.4.12 (pages 2 and 3), to the CTS markup for ITS 5.6, pages 8 of 9 and 9 of 9, to the Discussion of Changes M.3 to ITS 5.6 (page 2), to the NUREG-1434 ITS markup, page 1.1-6, to the Justification for Deviations to Chapter 1.0, comment number 8 (page 1), to the NUREG-1434 ITS markup, pages 3.3-20, 3.3-21, 3.4-24, 3.4-25, 3.4-26, Insert page 3.4-26, 3.4-27, and new Insert pages 3.4-27a, 3.4-27b, and 3.4-27c, to the Justifications for Deviation to Section 3.4, comment number 17 (page 3), to the NUREG-1434 ITS markup, pages 5.0-20, 5.0-21, and 5.0-22, to the Justification for Deviations to Chapter 5.0, comment number 32 (page 4), and to the NUREG-1434 Bases markup, pages B 3.3-60, B 3.3-62, B 3.4-52 through B 3.4-54, B 3.4-57, B 3.4-58, Insert page B 3.4-58, B 3.4-59, and Insert page B 3.4-59.

7. Specification 3.4.2, FCVs, pages 3.4-5, 3.4-6, and B 3.4-11 through B 3.4-14.

   A plant modification has been recently completed that deenergized the FCVs in the open position and added an Adjustable Speed Drive System to control the speed of the recirculation pumps. This change was approved in amendment 145 to the CTS. Therefore, the FCV Specification has been deleted and all other Section 3.4 Specifications have been renumbered due to the deletion.

   Corresponding Changes have been made to the applicable ITS of Sections 3.4, 3.7 and 3.10, to the applicable Bases of 3.0, 3.3, 3.4, 3.7, and 3.10, to the applicable CTS markups and Discussion of Changes for Sections 3.2, 3.4, 3.5, and 3.6, to the applicable NSHE for Section 3.4, to the applicable NUREG-1434 ITS markups and Justification for Deviations for Sections 3.4, 3.7, and 3.10, and the NUREG-1434 Bases markups and Justification for Deviations for Section 3.0, 3.3, 3.4, 3.7 and 3.10.

## SUMMARY OF CHANGES

8. Discussion of Changes L.2 to ITS 3.3.3.2 (page 7) and Discussion of Changes L.3 to ITS 3.3.8.2 (page 3).

   Additional justification was provided to support the allowance to place a PAM or RPS electric power monitoring channel in an inoperable status for up to 6 hours to perform required Surveillances without requiring entry into associated Conditions and Required Actions. This was requested by the NRC reviewer for Section 3.3 (comments 47 and 99).

9. Specification 5.5.9, Diesel Fuel Oil Testing Program, pages 5.0-14, B 3.8-47, B 3.8-48, and B 3.8-49.

   The reference to performing the required tests in accordance with "procedures based on" applicable ASTM Standards has been deleted. The tests will be performed in accordance with the ASTM Standards. This change was requested by the NRC reviewer for Chapter 5.0.

   Corresponding changes have also been made to the CTS markup for Specification 5.5 (page 21 of 21), to the NUREG-1434 ITS markup, page 5.0-14, to the Justification for Deviations to Chapter 5.0, comment number 24 (page 3), and to the NUREG-1434 Bases markup, pages B 3.8-47 and B 3.8-48.

10. Discussion of Changes LA.2 to ITS 3.8.5 (page 2) and Discussion of Changes LA. 1 to ITS 3.8.6 (page 2).

    The Discussion of Changes have been clarified to state the 24 volt DC battery requirements will be moved to the Licensee Controlled Specifications Manual, instead of the generic "plant procedures."

11. Discussion of Changes LA.1 to ITS Chapter 2.0 (page 1), Discussion of Changes LC.1 to ITS 3.1.5 (page 3), Discussion of Changes LA.1 and LA.4 to ITS 3.1.7 (pages 2 and 3), Discussion of Changes R.1 and LA.2 to ITS 3.2.4 (pages 1 and 2), Discussion of Changes LA.3, LA.6, and LA.7 to ITS 3.3.1.1 (pages 4 and 5), Discussion of Changes LA.3 to ITS 3.3.1.2 (page 2), Discussion of Changes R.1 and LA.1 to ITS 3.3.2.1 (pages 1 and 2), Discussion of Changes LA.1 to ITS 3.3.2.2 (page 1), Discussion of Changes R.1 to ITS 3.3.3.1 (page 2), Discussion of Changes LA.1 and LA.2 to ITS 3.3.4.1 (page 2), Discussion of Changes LA.1 to ITS 3.3.4.2 (page 1), Discussion of Changes R.1 and LA.1 to ITS 3.3.5.1 (pages 2 and 5), Discussion of Changes LA.1 to ITS 3.3.5.2 (page 2), Discussion of Changes R.1, LA.1, LA.6, and LA.7 to ITS 3.3.6.1 (pages 3, 4, 5, and 6), Discussion of Changes LA.1 to ITS 3.3.6.2 (page 3), Discussion of Changes LA.1 to ITS 3.3.7.1 (page 3), Discussion of Changes LA.1 and LA.4 to ITS

SUMMARY OF CHANGES

11. (continued)

3.3.8.1 (page 3), Discussion of Changes R.1 to CTS 3/4.3.7.1 (page 1), Discussion of Changes R.1 to CTS 3/4.3.7.3 (page 1), Discussion of Changes R.1 to CTS 3/4.3.7.7 (page 1), Discussion of Changes R.1 to CTS 3/4.3.7.10 (page 1), Discussion of Changes R.1 to CTS 3/4.3.7.12 (page 1), Discussion of Changes R.1 to CTS 3/4.3.8 (page 1), Discussion of Changes LA.3 to ITS 3.4.1 (page 4), Discussion of Changes LA.2 to ITS 3.4.7 (new 3.4.6) (page 2), Discussion of Changes LA.1 to ITS 3.4.9 (new 3.4.8) (page 1), Discussion of Changes LA.3 to ITS 3.4.12 (new 3.4.11) (page 4), Discussion of Changes R.1 to CTS 3/4.4.4 (page 1), Discussion of Changes R.1 to CTS 3/4.4.8 (page 1), Discussion of Changes LC.1 to ITS 3.5.1 (page 3), Discussion of Changes LA.3 to ITS 3.6.1.3 (page 4), Discussion of Changes R.1 to ITS 3.6.1.5 (page 1), Discussion of Changes LA.2 to ITS 3.6.1.6 (page 2), Discussion of Changes LA.3 and LC.1 to ITS 3.6.1.8 (page 2), Discussion of Changes LA.1 to ITS 3.6.2.1 (page 2), Discussion of Changes LC.1 to ITS 3.6.3.1 (page 2), Discussion of Changes LA.1 to ITS 3.6.4.1 (page 2), Discussion of Changes LA.1 to ITS 3.7.7 (page 1), Discussion of Changes R.1 to CTS 3/4.7.5 (page 1), Discussion of Changes R.1 to CTS 3/4.7.8 (page 1), Discussion of Changes LA.2, LA.3, LA.4, LA.7, and LA.8 to ITS 3.8.1 (pages 5, 6 and 7), Discussion of Changes LA.1 to ITS 3.8.2 (page 3), Discussion of Changes LA.1 to ITS 3.8.3 (page 2), Discussion of Changes LA.2 to ITS 3.8.7 (page 2), CTS markup for Specification 3.8.8, page 1 of 2, Discussion of Changes LA.3 (new) to ITS 3.8.8 (page 3), Discussion of Changes R.1 to CTS 3/4.8.4.1 (page 1), Discussion of Changes R.1 to CTS 3/4.8.4.2 (page 1), Discussion of Changes R.1 to CTS 3/4.8.4.3, Discussion of Changes LC.1 to ITS 3.9.5 (page 2), Discussion of Changes R.1 to CTS 3/4.9.4 (page 1), Discussion of Changes R.1 to CTS 3/4.9.5 (page 1), Discussion of Changes R.1 to CTS 3/4.9.6 (page 1), Discussion of Changes R.1 to CTS 3/4.9.7, Discussion of Changes LA.1 to ITS 3.10.1 (page 1), Discussion of Changes LA.3 and LA.4 to ITS 5.2 (pages 2 and 3), Discussion of Changes LA.4, LA.5, LA.6, and LA.7 to ITS 5.5 (pages 4 and 5), Discussion of Changes LA.1 to CTS 6.6 (page 1), and Discussion of Changes LA.1 to CTS 6.7 (page 1).

The Discussion of Changes have been clarified to state which document the relocated requirements are being moved to, such as the Licensee Controlled Specifications Manual, FSAR, etc, instead of the generic "plant documents." In addition, the proper change control process (e.g., 10 CFR 50.59, etc.) has also been provided.

12. Specification 1.1, Isolation Instrumentation Response Time definition, page 1.1-3, and Specification 3.3.6.1, Primary Containment Isolation Instrumentation, SR 3.3.6.1.7, pages 3.3-54 and B 3.3-178.

## SUMMARY OF CHANGES

12. (continued)

The title of the definition has been changed to "Isolation System Response Time" and the description of the time interval has been changed to include the valve stroke time. This was requested by the NRC reviewer and resolves Section 3.3, comment number 57.

Corresponding changes have also been made to the CTS markup for Chapter 1.0, page 5 of 18, to the Discussion of Changes A.10 to ITS Chapter 1.0 (page 3), to the CTS markup for Specification 3.3.6.1, page 2 of 12, to the Discussion of Changes A.3 to ITS 3.3.6.1 (page 1), to the NUREG-1434 ITS markup, pages 1.1-3 and 1.1-4, to the Justification for Deviations to Chapter 1.0, comment number 5 (page 1), to the NUREG-1434 ITS markup, page 3.3-55, to the Justification for Deviations to Section 3.3, comment number 9 (page 2), and to the NUREG-1434 Bases markup, pages B 3.3-175, B 3.3-176, and Insert Page B 3.3-176.

13. Specification 3.3.8.1, LOP Instrumentation, ACTIONS Table and Table 3.3.8.1-1, Required Channels Per Division for Functions 1.a, 1.b, 2.a, and 2.b, pages 3.3-68, 3.3-69, B 3.3-208, B 3.3-210, B 3.3-211, and B 3.3-212.

The minimum number of required channels for the loss of voltage Functions has been increased from 1 to 2, and the time allowed to restore a channel has been increased from 1 hour to 24 hours, consistent with the current licensing basis.

Corresponding changes have also been made to the CTS markup for Specification 3.3.8.1, pages 1 of 5, 2 of 5, and 3 of 5, to the Discussion of Changes M.1 and L.1 to ITS 3.3.8.1 (pages 1, 2, and 5), to the NUREG-1434 ITS markup, pages 3.3-80, Insert Page 3.3-80, and 3.3-82, to the Justification for Deviations to Section 3.3, comment numbers 41 and 46 (new) (pages 6, 7, and 8), and to the NUREG-1434 Bases markup, pages B 3.3-235, Insert Page B 3.3-235, B 3.3-237, and new Insert Page B 3.3-237.

14. LCO 3.0.5, pages 3.0-2, B 3.0-6, and B 3.0-7.

The allowance that LCO 3.0.5 can be used to demonstrate a Technical Specification variable is within limits has been deleted, since the generic change was rejected by the NRC.

Corresponding changes have also been made to the CTS markup for Section 3.0, page 3 of 8, to the NUREG-1434 ITS markup, page 3.0-2, and to the NUREG-1434 Bases markup, page B 3.0-7.

## SUMMARY OF CHANGES

15. Specification 3.3.5.1, ECCS Instrumentation, Table 3.3.5.1-1, Allowable Value for Functions 4.f and 5.e, page 3.3-46.

    The Allowable Value for the ADS Accumulator Backup Compressed Gas System Pressure-Low Function has been changed to be consistent with the most recent setpoint calculation. The new Allowable Value is still more conservative than the CTS Allowable Value.

    Corresponding changes have also been made to the CTS markup for Specification 3.3.5.1, page 12 of 12, to the Discussion of Changes M.2 to ITS 3.3.5.1 (page 3), and to the NUREG-1434 ITS markup, pages 3.3-44 and 3.3-45.

16. Specification 3.3.1.1, RPS Instrumentation, Condition C, page 3.3-1 and B 3.3-22.

    Condition C has been modified to require the RPS trip capability to be restored if one manual RPS Function is inoperable. The proposed ITS allowed one manual RPS Function to be inoperable for 12 hours, and only required restoration in 1 hour when both manual RPS Functions were inoperable. This change was requested by the NRC reviewer and resolves Section 3.3, comment 25.

    Corresponding changes have also been made to the Discussion of Changes M.1 to ITS 3.3.1.1 (page 4), to the NUREG-1434 ITS markup, page 3.3-1, to the Justification for Deviations to Section 3.3, comment number 1 (page 1), and to the NUREG-1434 Bases markup, page B 3.3-22.

17. Bases 3.3.5.1, ECCS Instrumentation, page B 3.3-103, and Bases 3.3.8.1, LOP Instrumentation, page B 3.3-207.

    The Allowable value description has been modified to clarify that for those Functions with both an upper and lower Allowable Value, each of the Allowable Values are unique and have an associated analytic limit and trip setpoint. This change was requested by the NRC reviewer.

    Corresponding changes have also been made to the NUREG-1434 Bases markup, pages B 3.3-99, new Insert page B 3.3-99, B 3.3-235, and Insert page B 3.3-235.

18. Specification 3.3.2.1, Control Rod Block Instrumentation, Table 3.3.2.1-1, SR 3.3.2.1.1 for Functions 1.a and 1.c, page 3.3-20; and Specification 3.3.5.1, ECCS Instrumentation, Table 3.3.5.1-1, SR 3.3.5.1.2 for Functions 1.e, 2.e, 4.b, and 5.b, pages 3.3-43, 3.3-44, 3.3-45, and 3.3-46.

## SUMMARY OF CHANGES

18. (continued)

When the Channel Calibration Frequency was the same as the Channel Functional Test Frequency, the proposed ITS did not list a Channel Functional Test Requirement since the Channel Calibration definition includes a Channel Functional Test. However, the NRC reviewer requested the Channel Functional Test requirement be added for completeness. This resolves Section 3.3, comment number 30.

Corresponding changes have also been made to the CTS markup for Specification 3.3.2.1, page 5 of 8, to the Discussion of Changes A.2 to ITS 3.3.2.1 (page 1), to the CTS markup for Specification 3.3.5.1, pages 9 of 12 and 10 of 12, to the Discussion of Changes A.11 to ITS 3.3.5.1 (page 2), to the NUREG-1434 ITS markup, pages Insert page 3.3-19f, 3.3-41, 3.3-42, 3.3-44, and 3.3-45, and to the Justification for Deviations to Section 3.3, comment number 26 (page 4).

19. Specification 3.6.2.3, RHR Suppression Pool Cooling, ACTIONS B and C, pages 3.6-31 and B 3.6-62.

The allowance in ACTION B to operate for 8 hours with both RHR Suppression Pool Cooling subsystems inoperable has been deleted. When both subsystems are inoperable, a shutdown will be required. Since ACTION B has been deleted, ACTION C, the shutdown action, has been renumbered to ACTION B, and new Condition B has been modified to cover the case where both subsystems are inoperable.

Corresponding changes have also been made to the CTS markup for Specification 3.6.2.3, page 1 of 1, to the Discussion of Changes L.1 to ITS 3.6.2.3 (page 2), to the NSHE for ITS 3.6.2.3, L.1, page 1, to the NUREG-1434 Its markup, page 3.6-33, to the Justification for Deviation to Section 3.6, comment number 29 (page 6), and to the NUREG-1434 Bases markup, page B 3.6-67.

20. Discussion of Changes LA.1 to CTS 3/4.7.4 (page 1).

The Discussion of Changes have been clarified to state the Snubber inspection and testing requirements will be moved to the Licensee Controlled Specifications Manual, instead of the generic "plant procedures." In addition, snubber testing will be maintained consistent with the CTS (the proposed change to test per the OM Code is withdrawn).

21. Specification 5.5.7, VFTP, pages 5.0-12 and 5.0-13.

The references to ANSI N510-1989 have been changed to ASME N510-1989, as requested by the NRC reviewer.

## SUMMARY OF CHANGES

21. (continued)

Corresponding changes have also been made to the CTS markup for Specification 5.5, pages 15 of 21 through 18 of 21, to the Discussion of Changes A.9 and L.1 to ITS 5.5 (pages 2 and 6), and to the NUREG-1434 ITS markup, pages 5.0-12 and 5.0-13.

22. Specification 3.6.1.7, Suppression Chamber-to-Drywell Vacuum Breakers, Condition C, pages 3.6-23 and B 3.6-46.

The allowance that "Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker" has been deleted from Condition C. This change was requested by the NRC reviewer.

Corresponding changes have also been made to the CTS markup for Specification 3.6.1.7, page 1 of 2, to the NUREG-1434 ITS markup, Insert page 3.6-24e, and to the NUREG-1434 Bases markup, Insert page B 3.6-47k.

23. Specification 5.5.1, ODCM, page 5.0-7; Specification 5.5.4, Radioactive Effluent Controls Program, page 5.0-9; Specification 5.6.1, Occupational Radiation Exposure Report, page 5.0-19; and Specification 5.7, High Radiation Area, pages 5.0-24 and 5.0-25.

Changes have been made to reflect the most recent NRC guidelines as requested by the NRC reviewer during phone conversations with the Licensee. In addition, justification was provided to guard a high radiation area in lieu of a locked door or gate.

Corresponding changes have also been made to the CTS markup for Specification 5.6, page 2 of 9, to the Discussion of Changes A.7 to ITS 5.6 (page 1), to the NUREG-1434 ITS markup, pages 5.0-7, 5.0-8, 5.0-9, 5.0-18, Insert Page 5.0-25a, and Insert Page 5.0-25b, and to the Justification for Deviations to Chapter 5.0, comment number 30 (page 4).

24. Specification 3.6.1.3, PCIVs, Condition D, pages 3.6-12, B 3.6-18, B 3.6-19, B 3.6-20, and B 3.6-21.

The type of leakage this Condition applies to has been added. The current words just refer to "leakage," while the new words refer to "secondary containment bypass leakage," "MSIV leakage," and "hydrostatically tested lines leakage." This change was requested by the NRC reviewer.

## SUMMARY OF CHANGES

24. (continued)

Corresponding changes have also been made to the NUREG-1434 ITS markup, page 3.6-11, and to the NUREG-1434 Bases markup, pages B 3.6-19, B 3.6-20, B 3.6-21, and B 3.6-22.

25. Specification 5.5.9, Diesel Fuel Oil Testing Program, page 5.0-15.

The specific ASTM standard that provides the method to test diesel fuel oil total particulate has been added. This change was requested by the NRC reviewer.

Corresponding changes have also been made to the CTS markup for Specification 5.5, page 21 of 21, to the NUREG-1434 ITS markup, page 5.0-15, and to the Justification for Deviations to Chapter 5.0, comment number 24 (page 3).

26. Specification 3.3.4.2, ATWS-RPT Instrumentation, SR 3.3.4.2.3, page 3.3-35.

The Allowable Value for the Reactor Vessel Steam Dome Pressure-High Function has been decreased to the value specified in the most recent setpoint calculation.

Corresponding changes have also been made to the CTS markup for Specification 3.3.4.2, page 3 of 4, and to the NUREG-1434 ITS markup, page 3.3-33.

27. Discussion of Changes L.1 to Chapter 4.0 (page 3).

The reference to the "safe shielding level" has been deleted as requested by the NRC reviewer.

28. Specification 5.3, Unit Staff Qualifications, page 5.0-5.

Changes have been made to the qualification requirements for the Operations Manager. The changes reflect the new requirements recently approved by the NRC in Amendment 148 to the WNP-2 Technical Specifications.

Corresponding changes have also been made to the CTS markup for Specification 5.2, page 5 of 5, to the CTS markup for Specification 5.3, page 1 of 1, and to the NUREG-1434 ITS markup, pages 5.0-5 and Insert Page 5.0-5.

29. Specification 5.5.9, Diesel Fuel Oil Testing Program, page 5.0-14.

## SUMMARY OF CHANGES

29. (continued)

The circumstances under which the kinematic viscosity test must be performed have been added. Currently, this is only specified in the Bases to Specification 3.8.3. This change was requested by the NRC reviewer.

Corresponding changes have also been made to the CTS markup for Specification 5.5, page 21 of 21, and to the NUREG-1434 ITS markup, page 5.0-15.

30. Specification 5.5.7, Ventilation Filter Testing Program, pages 5.0-12 and 5.0-13.

The specific section numbers of the applicable regulatory guide and ASTM standards that provide the details of the required tests has been deleted to be consistent with NUREG-1434 (which does not list the specific section numbers).

Corresponding changes have also been made to the CTS markup for Specification 5.5, pages 15 of 21 and 17 of 21, to the Discussion of Changes A.9 and L.1 to ITS 5.5 (pages 2 and 6), and to the NUREG-1434 ITS markup, pages 5.0-12 and 5.0-13.

31. Specification 3.3.6.1, Primary Containment Isolation Instrumentation, Table 3.3.6.1-1, Function 4.c, Surveillance Requirements column, page 3.3-56, CTS markup for Specification 3.3.6.1, pages 4 of 12, 6 of 12, 8 of 12, and 11 of 12, and Discussion of Changes M.4, LA.8 (new), and LE.1 to ITS 3.3.6.1 (pages 3, 6, 7, 8, and 9).

Changes have been made to reflect Amendment 147 to the WNP-2 Technical Specifications. This recently approved amendment added the RWCU Blowdown Flow-High Function to the WNP-2 Technical Specifications. This change only affects the CTS markup, since the original WNP-2 ITS and Bases submittal already includes this Function. In addition, the Frequency for the Channel Calibration has been extended from 18 months to 24 months. This instrument has many components that are common with Function 4.a, RWCU Differential Flow - High, which was previously proposed (in the original ITS submittal) to have a 24 month Channel Calibration Frequency.

Corresponding changes have also been made to the CTS markup for Specification 3.3.6.2, page 4 of 8 and to the NUREG-1434 ITS markup, page 3.3-60.

## SUMMARY OF CHANGES

32. Specification 5.2, Organization, page 5.0-2.

The title of the Assistant Managing Director for Operations was changed to Vice-President, Nuclear Operations in Revision A of the WNP-2 ITS. Subsequently, the title Vice-President, Nuclear Operations has been changed to Chief Executive Officer, as it relates to the person with corporate responsibility for overall plant nuclear safety. Therefore, the title in Specification 5.2.1.c is being changed to the current title for the described position. The actual person holding this title has not changed.

Corresponding changes have also been made to the CTS markup for Specification 5.2, page 1 of 5, to the Discussion of Changes A.1 to ITS 5.2 (page 1), and to the NUREG-1434 ITS markup, page 5.0-2.

33. Specification 3.3.1.1, RPS Instrumentation, SR 3.3.1.1.15, pages 3.3-6, B 3.3-30, and B 3.3-31; Specification 3.3.5.1, ECCS Instrumentation, SR 3.3.5.1.7 (new), pages 3.3-42, 3.3-43, 3.3-44, 3.3-45, B 3.3-103, and B 3.3-131, Specification 3.3.6.1, Primary Containment Isolation Instrumentation, SR 3.3.6.1.7, pages 3.3-54 and B 3.3-178; Specification 3.5.1, ECCS-Operating, SR 3.5.1.8 (deleted), pages 3.5-5, and B 3.5-13; and Specification 3.5.2, ECCS-Shutdown, SR 3.5.2.7 (deleted), pages 3.5-9 and B 3.5-19.

The Notes to the response time Surveillances, which allow certain sensors and instruments to not be response time tested, have been deleted based on discussions with the NRC reviewer. In addition, the ECCS RESPONSE TIME Surveillance has been moved from Specifications 3.5.1 and 3.5.2 (the system Specifications) to Specifications 3.3.5.1 (the instrumentation Specification) to be consistent with NUREG-1434.

Corresponding changes have also been made to the CTS markup for Specification 3.3.1.1, page 1 of 11, to the Discussion of Changes A.3 to ITS 3.3.1.1 (page 1), to the CTS markup for Specification 3.3.5.1, page 1 of 12, to the Discussion of Changes A.2 and LD.1 to ITS 3.3.5.1 (pages 1 and 5), to the CTS markup for Specification 3.3.6.1, page 2 of 12, to the Discussion of Changes A.3 to ITS 3.3.6.1 (page 1), to the CTS markup for Specification 3.5.1, page 6 of 6 (deleted), to the Discussion of Changes A.5 (deleted) to ITS 3.5.1 (page 1), to the CTS markup for Specification 3.5.2, page 5 of 5 (deleted), to the Discussion of Changes A.7 (deleted) and LD.1 (deleted) to ITS 3.5.2 (pages 2 and 3), to the NUREG-1434 ITS markup, pages 3.3-6, 3.3-40, 3.3-41, 3.3-42, 3.3-43, and 3.3-55, to the Justification for Deviations to Section 3.3, comment number 9 (deleted)(page 1), to the NUREG-1434 ITS markup, pages 3.5-6 and 3.5-10, to the

## SUMMARY OF CHANGES

33. (continued)

Justifications for Deviations to Section 3.5, comment number 7 (deleted)(page 1), and to the NUREG-1434 Bases markup, pages B 3.3-31, Insert Page B 3.3-31 (deleted), B 3.3-32, B 3.3-98, B 3.3-128B 3.3-176, Insert Page B 3.3-176 (deleted), B 3.5-13, Insert Page B 3.5-13 (deleted), and B 3.5-17.

34. Specification 1.3, Completion Times, Examples 1.3-3 and 1.3-6, pages 1.3-6 and 1.3-10.

The two examples have been modified to reflect NUREG-1434, Revision 1. A generic change was proposed to these two examples (TSTF-31) to correct discrepancies. WNP-2 submitted the ITS with this generic change incorporated. However, since this generic change has been rejected, WNP-2 has changed the examples back to their original form.

Corresponding changes have also been made to the NUREG-1434 ITS markup, pages 1.3-6 and 1.3-10.

35. Bases 3.3.1.1, RPS Instrumentation, page B 3.3-31, Bases 3.3.4.1, EOC-RPT Instrumentation, page B 3.3-86, Bases 3.4.1, Recirculation Loops Operating, pages B 3.4-3, B 3.4-9, and B 3.4-10, Bases 3.4.3 (old B 3.4.4), SRVs - $\geq$ 25% RTP, page B 3.4-19, Bases 3.4.4 (old B 3.4.5), SRVs -< 25% RTP, page B 3.4-24, Bases 3.4.12 (old B 3.4.13), Reactor Steam Dome Pressure, page B 3.4-65, Bases 3.5.1, ECCS-Operating, page B 3.5-14, Bases 3.6.1.3, PCIVs, page B 3.6-28.

Changes have been made to some of the references (in Chapters 6 and 15/15F) due to changes to the FSAR, as reflected in Amendment 51 to the FSAR.

Corresponding changes have also been made to the NUREG-1434 Bases markup, pages B 3.3-32, B 3.3-81, B 3.4-2, Insert Page B 3.4-3, B 3.4-6, Insert Page B 3.4-6, B 3.4-21, Insert Page B 3.4-21, Insert Page B 3.4-21g, B 3.4-62, B 3.5-13, and B 3.6-32.

36. Bases 3.1.8, SDV Vent and Drain Valves, page B 3.1-47.

The words in the Applicability that state "This provides adequate controls to ensure that only a single control rod can be withdrawn" have been deleted. This statement is incorrect since it follows the statement that "In MODES 3 and 4, control rods are not able to be withdrawn since a control rod block is applied."

Corresponding changes have also been made to the NUREG-1434 Bases markup, page B 3.1-47.

## SUMMARY OF CHANGES

37. Specification 3.3.8.1, LOP Instrumentation, Functions 1.b, 1.c, 1.d, and 2.b, Allowable Value column, page 3.3-71.

The Allowable Values for these Functions have been changed to be consistent with the most recent setpoint calculations. The new calculations now account for the 15 second Diesel Generator start time delay that is assumed in the safety analyses. The 15 second time delay was submitted in the original ITS submittal.

Corresponding changes have also been made to the NUREG-1434 ITS markup, page 3.3-82.

38. Specification 3.3.1.1, RPS Instrumentation, Function 1.a, Allowable Value column, page 3.3-7.

The Allowable Value for the IRM Neutron Flux-High Function has been changed to be consistent with the most recent setpoint calculation. This new Allowable Value is the same as the CTS Allowable Value.

Corresponding changes have also been made to the CTS markup for Specification 3.3.1.1, page 10 of 11, and to the NUREG-1434 ITS markup, page 3.3-7.

39. Specification 3.8.1, AC Sources - Operating, SR 3.8.1.9, SR 3.8.1.10, and SR 3.8.1.14, pages 3.8-9, 3.8-13, B 3.8-22, B 3.8-23, B 3.8-24, B 3.8-28, and B 3.8-29.

Note 2 to SR 3.8.1.9 has been changed to state that the SR shall be performed at a power factor as close to the single largest post-accident load as practicable. Currently the SR Note only requires it to be maintained as close to a power factor limit as practicable, with the limit specified in the Bases. Note 2 to SR 3.8.1.10 and Note 3 to SR 3.8.1.14 have been modified to state that if the SR is performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident power factor as practicable with the field excitation current $\geq$ 90% of the continuous rating. Currently, the SRs require the test to be performed at the power factor limit (with the limit specified in the Bases), and the Notes provide an allowance such that if the power factor limit cannot be met, the power factor shall be maintained as close to the limit as practicable (the new wording of the Notes adds an additional limit - excitation current $\geq$ 90% - when the power factor limit is not met). These changes are the result of discussions with the NRC reviewers.

Corresponding changes have also been made to NUREG-1434 ITS markup, pages 3.8-9, 3.8-10, and 3.8-14, and to the NUREG-1434 Bases markup, pages B 3.8-22, Insert Page B 3.8-22, B 3.8-23, Insert Page B 3.8-23, B 3.8-28, and Insert Page B 3.8-28.

## SUMMARY OF CHANGES

40. Technical Specifications - Editorial Changes/Typographical Errors.

Minor changes are proposed to the following Technical Specifications for consistency, clarity, or to correct typographical errors:

Specification 3.3.2.1, Required Action D.1, page 3.3-16;

Specification 3.3.5.1, Table 3.3.5.1-1, Applicability for Functions 1.d, 1.f, 2.d, 2.e, 2.f, and 2.g, pages 3.3-43 and 3.3-44;

Specification 3.3.6.1, Table 3.3.6.1-1, Allowable Value for Function 5.e, page 3.3-58; and

Specification 3.3.7.1, Table 3.3.7.1-1, Applicability for Function 3, page 3.3-67.

41. Bases - Editorial Changes/Typographical Errors.

Minor changes are proposed to the following Technical Specifications Bases for consistency, clarity, or to correct typographical errors:

B 3.1.7, Applicable Safety Analyses, page B 3.1-40;

B 3.3.1.1, Surveillance Requirements Section, page 3.3-28;

B 3.3.2.2, Surveillance Requirements Section and References Section, pages B 3.3-57 and B 3.3-59;

B 3.3.4.1, Applicable Safety Analyses, LCO, and Applicability Sections, page B 3.3-78;

B 3.3.5.1, Actions and References Sections, pages B 3.3-124 and B 3.3-131;

B 3.3.8.1, Background Section, page B 3.3-205;

B 3.4.1, Applicable Safety Analyses and References Sections, pages B 3.4-3 and B 3.4-9;

B 3.4.4 (new B 3.4.3), References Section, page B 3.4-19;

B 3.4.12 (new B 3.4.11), Background, LCO, and Surveillance Requirements Sections, pages B 3.4-54, B 3.4-55, and B 3.4-60;

## SUMMARY OF CHANGES

41. (continued)

B 3.5.1, References Section, page B 3.5-14;

B 3.8.1, Applicability, Actions, and Surveillance Requirements Sections, pages B 3.8-6, B 3.8-11, B 3.8-17, B 3.8-21, and B 3.8-29;

B 3.8.3, Background Section, page B 3.8-41;

B 3.8.6, Surveillance Requirements Section, page B 3.8-71; and

B 3.8.7, Applicability Section, page B 3.8-76.

42. CTS Markups and Discussion of Changes - Editorial Changes/Typographical Errors.

Minor changes are proposed to the following CTS markups and Discussion of Changes for consistency, clarity, or to correct typographical errors:

Discussion of Changes A.21 to ITS Chapter 1.0 (page 5);

CTS markup for ITS 3.3.1.1, page 6 of 11;

Discussion of Changes L.11 to ITS 3.3.6.1 (page 17);

Discussion of Changes A.5 to ITS 3.4.1 (page 1);

Discussion of Changes L.11 to ITS 3.6.1.3 (page 7);

Discussion of Changes M.1 to ITS 3.6.4.1 (page 1);

Discussion of Changes LA.2 to ITS 3.7.5 (page 2);

Discussion of Changes LA.3 to ITS 5.2 (page 2);

Discussion of Changes M.1 to ITS 5.4 (page 1);

Discussion of Changes LA.4 and LA.6 to ITS 5.5 (page 4); and

Discussion of Changes M.1 to ITS 5.6 (page 2).

## SUMMARY OF CHANGES

43. NUREG ITS Markup and Justification for Deviations - Editorial Changes/Typographical Errors.

    Minor changes are proposed to the following NUREG ITS markups and Justification for Deviations for consistency, clarity, or to correct typographical errors:

    Specification 3.1.5, Required Actions A.1 and B.2.1, pages 3.1-16 and 3.1-17;

    Specification 3.3.2.1, Required Action D.1, page 3.3-16;

    Specification 3.3.7.1, Table 3.3.7.1-1, Applicability for Function 3, page 3.3-79;

    Specification 3.3.8.2, LCO, page 3.3-83; and

    Specification 3.7.1, Condition C, page 3.7-3.

44. NUREG Bases Markup and Justification for Deviations - Editorial Changes/Typographical Errors.

    Minor changes are proposed to the following NUREG Bases markups and Justification for Deviations for consistency, clarity, or to correct typographical errors:

    Bases 3.3.2.2, Surveillance Requirements Section and References Section, Insert pages B 3.3-52s and B 3.3-52u;

    Bases 3.3.4.1, Applicable Safety Analyses, LCO, and Applicability Sections, page 3.3-72;

    Bases 3.3.5.1, Actions and References Sections, pages B 3.3-120 and B 3.3-128;

    Bases 3.4.1, Applicable Safety Analyses, Surveillance Requirements, and References Sections, Insert Page B 3.4-3, page B 3.4-6, and Insert page B 3.4-6;

    Bases 3.4.4 (new 3.4.3), References Section, Insert Page B 3.4-21;

    Bases 3.4.12 (new 3.4.11), Background, LCO, and Surveillance Requirements Sections, pages B 3.4-53 and B 3.4-54, and Insert Page B 3.4-58;

    Bases 3.5.1, References Section, page B 3.5-13;

## SUMMARY OF CHANGES

44. (continued)

Bases 3.8.1, Applicability, Actions, and Surveillance Requirements Sections, pages B 3.8-4, B 3.8-9, B 3.8-16, B 3.8-21, and B 3.8-29;

Bases 3.8.3, Background Section, Insert Page B 3.8-42;

Bases 3.8.6, Surveillance Requirements Section, page B 3.8-70; and

Bases 3.8.7, Applicability Section, page B 3.8-83.

50-397 WPPSS WNP-2

ATTACHMENTS TO THE REQUEST FOR AMENDMENT TO TECH SPECS (PART 1 of 2)

Rec'd w/ ltr dtd 12/12/96......9612260193

# -NOTICE-

THE ATTACHED FILES ARE OFFICAL RECORDS OF THE OCIO/INFORMATION MANAGEMENT DIVISION. THEY HAVE BEEN CHARGED TO YOU FOR A LIMITED TIME PERIOD AND MUST BE RETURNED TO THE RECORDS AND ARCHIVES SERVICES SECTION, T-5C3. PLEASE DO NOT SEND DOCUMENTS CHARGED OUT THROUGH THE MAIL. REMOVAL OF ANY PAGE(S) FROM DOCUMENTS FOR REPRODUCTION MUST BE REFERRED TO FILE PERSONNEL.

# -NOTICE-

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 2, TECHNICAL SPECIFICATIONS | |
|---|---|
| DISCARD | INSERT |
| 1.1-3 | 1.1-3 |
| 1.1-6 through 1.1-7 | 1.1-6 through 1.1-7 |
| 1.3-6 | 1.3-6 |
| 1.3-10 | 1.3-10 |
| 3.0-2 | 3.0-2 |
| 3.3-1 through 3.3-7 | 3.3-1 through 3.3-7 |
| 3.3-16 | 3.3-16 |
| 3.3-20 | 3.3-20 |
| 3.3-23 through 3.3-24 | 3.3-23 through 3.3-24 |
| 3.3-33 | 3.3-33 |
| 3.3-35 | 3.3-35 |
| 3.3-42 through 3.3-46 | 3.3-42 through 3.3-46 |
| 3.3-54 | 3.3-54 |
| 3.3-56 | 3.3-56 |
| 3.3-58 | 3.3-58 |
| 3.3-67 through 3.3-74 | 3.3-67 through 3.3-74 |
| 3.4-5 through 3.4-30 | 3.4-5 through 3.4-31 |
| 3.5-1 through 3.5-2 | 3.5-1 through 3.5-2 |
| 3.5-5 through 3.5.13 | 3.5-5 through 3.5-12 |
| 3.5-10 | 3.5-10 |
| 3.6-12 | 3.6-12 |
| 3.6-23 | 3.6-23 |
| 3.6-31 | 3.6-31 |
| 3.7-2 | 3.7-2 |
| 3.8-2 through 3.8-3 | 3.8-2 through 3.8-3 |
| 3.8-5 | 3.8-5 |
| 3.8-9 through 3.8-40 | 3.8-9 through 3.8.39 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 2, TECHNICAL SPECIFICATIONS | |
|---|---|
| DISCARD | INSERT |
| 3.10-1 | 3.10-1 |
| 5.0-2 | 5.0-2 |
| 5.0-5 | 5.0-5 |
| 5.0-7 | 5.0-7 |
| 5.0-9 | 5.0-9 |
| 5.0-12 through 5.0-15 | 5.0-12 through 5.0-15 |
| 5.0-19 through 5.0-27 | 5.0-19 through 5.0-26 |
| VOLUME 3, BASES | |
| DISCARD | INSERT |
| B 2.0-2 through B 2.0-5 | B 2.0-2 through B 2.0-5 |
| B 3.0-2 | B 3.0-2 |
| B 3.0-6 through B 3.0-9 | B 3.0-6 through B 3.0-9 |
| B 3.1-35 through B 3.1-36 | B 3.1.35 through B 3.1-36 |
| B 3.1-38 through B 3.1-40 | B 3.1-38 through B 3.1-40 |
| B 3.1-47 | B 3.1-47 |
| B 3.2-1 through B 3.2-17 | B 3.2-1 through B 3.2-17 |
| B 3.3-2 through B 3.3-5 | B 3.3-2 through B 3.3-5 |
| B 3.3-10 through B 3.3-13 | B 3.3-10 through B 3.3-13 |
| B 3.3-16 | B 3.3-16 |
| B 3.3-20 through B 3.3-21 | B 3.3-20 through B 3.3-21 |
| B 3.3-22 | B 3.3-22 |
| B 3.3-24 through B 3.3-26 | B 3.3-24 through B 3.3-26 |
| B 3.3-28 | B 3.3-28 |
| B 3.3-30 through B 3.3-31 | B 3.3-30 through B 3.3-31 |
| B 3.3-43 through B 3.3-45 | B 3.3-43 through B 3.3-45 |
| B 3.3-48 through B 3.3-49 | B 3.3-48 through B 3.3-49 |
| B 3.3-51 through B 3.3-52 | B 3.3-51 through B 3.3-52 |
| B 3.3-57 | B 3.3-57 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 3, BASES | |
|---|---|
| DISCARD | INSERT |
| B 3.3-59 | B 3.3-59 |
| B 3.3-67 through B 3.3-68 | B 3.3-67 through B 3.3-68 |
| B 3.3-78 | B 3.3-78 |
| B 3.3-83 through B 3.3-87 | B 3.3-83 through B 3.3-87 |
| B 3.3-91 through B 3.3-94 | B 3.3-91 through B 3.3-94 |
| B 3.3-102 through B 3.3-220 | B 3.3-102 through B 3.3-222 |
| B 3.4-1 through B 3.4-69 | B 3.4-1 through B 3.4-65 |
| **VOLUME 4, BASES** | |
| DISCARD | INSERT |
| B 3.5-5 through B 3.5-27 | B 3.5-5 through B 3.5-26 |
| B 3.6-18 through B 3.6-21 | B 3.6-18 through B 3.6-21 |
| B 3.6-28 | B 3.6-28 |
| B 3.6-45 through B 3.6-46 | B 3.6-45 through B 3.6-46 |
| B 3.6-62 through B 3.6-63 | B 3.6-62 through B 3.6-63 |
| B 3.7-4 | B 3.7-4 |
| B 3.8-6 | B 3.8-6 |
| B 3.8-8 | B 3.8-8 |
| B 3.8-11 through B 3.8-12 | B 3.8-11 through B 3.8-12 |
| B 3.8-15 through B 3.8-86 | B 3.8-15 through B 3.8-87 |
| B 3.10-1 | B 3.10-1 |
| B 3.10-3 | B 3.10-3 |
| **VOLUME 5, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT** | |
| DISCARD | INSERT |
| CTS markup for Chapter 1.0 Page 1 of 19 through Page 19 of 19 | CTS markup for Chapter 1.0 Page 1 of 18 through Page 18 of 18 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 5, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| Discussion of Changes ITS Chapter 1.0 Pages 3 through 8 | Discussion of Changes ITS Chapter 1.0 Pages 3 through 8 |
| Discussion of Changes ITS Chapter 2.0 Page 1 | Discussion of Changes ITS Chapter 2.0 Page 1 |
| CTS markup for Section 3.0 Page 3 of 8 | CTS markup for Section 3.0 Page 3 of 8 |
| Discussion of Changes ITS 3.1.5 Page 3 | Discussion of Changes ITS 3.1.5 Page 3 |
| Discussion of Changes ITS 3.1.7 Pages 2 and 3 | Discussion of Changes ITS 3.1.7 Pages 2 and 3 |
| Discussion of Changes ITS 3.2.4 Pages 1 and 2 | Discussion of Changes ITS 3.2.4 Pages 1 and 2 |
| CTS markup for CTS 3/4.2.7 Page 1 of 2 | CTS markup for CTS 3/4.2.7 Page 1 of 2 |
| CTS markup for CTS 3/4.2.8 Page 1 of 2 | CTS markup for CTS 3/4.2.8 Page 1 of 2 |
| CTS markup for Specification 3.3.1.1 Page 1 of 11 | CTS markup for Specification 3.3.1.1 Page 1 of 11 |
| CTS markup for Specification 3.3.1.1 Page 6 of 11 | CTS markup for Specification 3.3.1.1 Page 6 of 11 |
| CTS markup for Specification 3.3.1.1 Page 10 of 11 | CTS markup for Specification 3.3.1.1 Page 10 of 11 |
| Discussion of Changes ITS 3.3.1.1 Pages 1 through 7 | Discussion of Changes ITS 3.3.1.1 Pages 1 through 7 |
| Discussion of Changes ITS 3.3.1.2 Page 2 | Discussion of Changes ITS 3.3.1.2 Page 2 |
| CTS markup for Specification 3.3.2.1 Page 5 of 8 | CTS markup for Specification 3.3.2.1 Page 5 of 8 |
| Discussion of Changes ITS 3.3.2.1 Pages 1 and 2 | Discussion of Changes ITS 3.3.2.1 Pages 1 and 2 |
| Discussion of Changes ITS 3.3.2.2 Page 1 | Discussion of Changes ITS 3.3.2.2 Page 1 |
| CTS markup for Specification 3.3.3.1 Page 4 of 6 | CTS markup for Specification 3.3.3.1 Page 4 of 6 |
| Discussion of Changes ITS 3.3.3.1 Page 2 through 3 | Discussion of Changes ITS 3.3.3.1 Page 2 through 3 |
| Discussion of Changes ITS 3.3.3.1 Page 9 | Discussion of Changes ITS 3.3.3.1 Page 9 |
| Discussion of Changes ITS 3.3.3.2 Page 7 | Discussion of Changes ITS 3.3.3.2 Page 7 |
| Discussion of Changes ITS 3.3.4.1 Page 2 | Discussion of Changes ITS 3.3.4.1 Page 2 |
| CTS markup for Specification 3.3.4.2 Page 1 of 4 | CTS markup for Specification 3.3.4.2 Page 1 of 4 |
| CTS markup for Specification 3.3.4.2 Page 3 of 4 | CTS markup for Specification 3.3.4.2 Page 3 of 4 |
| Discussion of Changes ITS 3.3.4.2 Pages 1 through 4 | Discussion of Changes ITS 3.3.4.2 Pages 1 through 4 |
| CTS markup for Specification 3.3.5.1 Page 1 of 12 | CTS markup for Specification 3.3.5.1 Page 1 of 12 |
| CTS markup for Specification 3.3.5.1 Page 9 of 12 through Page 10 of 12 | CTS markup for Specification 3.3.5.1 Page 9 of 12 through Page 10 of 12 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 5, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| CTS markup for Specification 3.3.5.1 Page 12 of 12 | CTS markup for Specification 3.3.5.1 Page 12 of 12 |
| Discussion of Changes ITS 3.3.5.1 Pages 1 through 3 | Discussion of Changes ITS 3.3.5.1 Pages 1 through 3 |
| Discussion of Changes ITS 3.3.5.1 Pages 5 through 8 | Discussion of Changes ITS 3.3.5.1 Pages 5 through 8 |
| Discussion of Changes ITS 3.3.5.2 Page 2 | Discussion of Changes ITS 3.3.5.2 Page 2 |
| CTS markup for Specification 3.3.6.1 Page 2 of 12 | CTS markup for Specification 3.3.6.1 Page 2 of 12 |
| CTS markup for Specification 3.3.6.1 Page 4 of 12 | CTS markup for Specification 3.3.6.1 Page 4 of 12 |
| CTS markup for Specification 3.3.6.1 Page 6 of 12 | CTS markup for Specification 3.3.6.1 Page 6 of 12 |
| CTS markup for Specification 3.3.6.1 Page 8 of 12 | CTS markup for Specification 3.3.6.1 Page 8 of 12 |
| CTS markup for Specification 3.3.6.1 Page 11 of 12 | CTS markup for Specification 3.3.6.1 Page 11 of 12 |
| Discussion of Changes ITS 3.3.6.1 Pages 1 through 18 | Discussion of Changes ITS 3.3.6.1 Pages 1 through 17 |
| Discussion of Changes ITS 3.3.6.1 Page 17 | Discussion of Changes ITS 3.3.6.1 Page 17 |
| CTS markup for Specification 3.3.6.2 Page 4 of 8 | CTS markup for Specification 3.3.6.2 Page 4 of 8 |
| Discussion of Changes ITS 3.3.6.2 Page 3 | Discussion of Changes ITS 3.3.6.2 Page 3 |
| Discussion of Changes ITS 3.3.7.1 Page 3 | Discussion of Changes ITS 3.3.7.1 Page 3 |
| CTS markup for Specification 3.3.8.1 Page 1 of 5 through Page 3 of 5 | CTS markup for Specification 3.3.8.1 Page 1 of 5 through Page 3 of 5 |
| Discussion of Changes ITS 3.3.8.1 Pages 1 through 6 | Discussion of Changes ITS 3.3.8.1 Pages 1 through 6 |
| CTS markup for Specification 3.3.8.2 Page 1 of 1 | CTS markup for Specification 3.3.8.2 Page 1 of 1 |
| Discussion of Changes ITS 3.3.8.2 Page 1 | Discussion of Changes ITS 3.3.8.2 Page 1 |
| Discussion of Changes ITS 3.3.8.2 Page 3 | Discussion of Changes ITS 3.3.8.2 Page 3 |
| Discussion of Changes CTS 3/4.3.7.1 Page 1 | Discussion of Changes CTS 3/4.3.7.1 Page 1 |
| Discussion of Changes CTS 3/4.3.7.3 Page 1 | Discussion of Changes CTS 3/4.3.7.3 Page 1 |
| Discussion of Changes CTS 3/4.3.7.7 Page 1 | Discussion of Changes CTS 3/4.3.7.7 Page 1 |
| Discussion of Changes CTS 3/4.3.7.10 Page 1 | Discussion of Changes CTS 3/4.3.7.10 Page 1 |
| Discussion of Changes CTS 3/4.3.7.12 Page 1 | Discussion of Changes CTS 3/4.3.7.12 Page 1 |
| Discussion of Changes CTS 3/4.3.8 Page 1 | Discussion of Changes CTS 3/4.3.8 Page 1 |
| CTS markup for Specification 3.4.1 Page 1 of 11 through Page 3 of 11 | CTS markup for Specification 3.4.1 Page 1 of 11 through Page 3 of 11 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 5, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| CTS markup for Specification 3.4.1 Page 7 of 11 | CTS markup for Specification 3.4.1 Page 7 of 11 |
| CTS markup for Specification 3.4.1 Page 9 of 11 | CTS markup for Specification 3.4.1 Page 9 of 11 |
| Discussion of Changes ITS 3.4.1 Page 1 through 2 | Discussion of Changes ITS 3.4.1 Page 1 through 2 |
| Discussion of Changes ITS 3.4.1 Page 4 through 6 | Discussion of Changes ITS 3.4.1 Page 4 through 7 |
| CTS markup for Specification 3.4.2 Page 1 of 1 | CTS markup for Specification 3.4.2 Page 1 of 1 |
| Discussion of Changes ITS 3.4.2 Page 1 through 2 | Discussion of Changes ITS 3.4.2 Page 1 |
| CTS markup for Specification 3.4.3 Page 1 of 1 | CTS markup for Specification 3.4.3 Page 1 of 2 through Page 2 of 2 |
| Discussion of Changes ITS 3.4.3 Page 1 | Discussion of Changes ITS 3.4.3 Page 1 through 2 |
| CTS markup for Specification 3.4.4 Page 1 of 2 through Page 2 of 2 | CTS markup for Specification 3.4.4 Page 1 of 2 through Page 2 of 2 |
| Discussion of Changes ITS 3.4.4 Page 1 through 2 | Discussion of Changes ITS 3.4.4 Page 1 through 2 |
| CTS markup for Specification 3.4.5 Page 1 of 2 through Page 2 of 2 | CTS markup for Specification 3.4.5 Page 1 of 2 through Page 2 of 2 |
| Discussion of Changes ITS 3.4.5 Page 1 through 2 | Discussion of Changes ITS 3.4.5 Page 1 through 2 |
| CTS markup for Specification 3.4.6 Page 1 of 2 through Page 2 of 2 | CTS markup for Specification 3.4.6 Page 1 of 3 through Page 3 of 3 |
| Discussion of Changes ITS 3.4.6 Page 1 through 2 | Discussion of Changes ITS 3.4.6 Page 1 through 3 |
| CTS markup for Specification 3.4.7 Page 1 of 3 through Page 3 of 3 | CTS markup for Specification 3.4.7 Page 1 of 1 |
| Discussion of Changes ITS 3.4.7 Pages 1 through 3 | Discussion of Changes ITS 3.4.7 Pages 1 through 2 |
| CTS markup for Specification 3.4.8 Page 1 of 1 | CTS markup for Specification 3.4.8 Page 1 of 3 through Page 3 of 3 |
| Discussion of Changes ITS 3.4.8 Pages 1 through 2 | Discussion of Changes ITS 3.4.8 Pages 1 through 3 |
| CTS markup for Specification 3.4.9 Page 1 of 3 through Page 3 of 3 | CTS markup for Specification 3.4.9 Page 1 of 1 |
| Discussion of Changes ITS 3.4.9 Pages 1 through 3 | Discussion of Changes ITS 3.4.9 Pages 1 through 2 |
| CTS markup for Specification 3.4.10 Page 1 of 1 | CTS markup for Specification 3.4.10 Page 1 of 1 |
| Discussion of Changes ITS 3.4.10 Pages 1 through 2 | Discussion of Changes ITS 3.4.10 Page 1 |
| CTS markup for Specification 3.4.11 Page 1 of 1 | CTS markup for Specification 3.4.11 Page 1 of 7 through Page 7 of 7 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 5, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| Discussion of Changes ITS 3.4.11 Page 1 | Discussion of Changes ITS 3.4.11 Pages 1 through 4 |
| CTS markup for Specification 3.4.12 Page 1 of 7 through Page 7 of 7 | CTS markup for Specification 3.4.12 Page 1 of 1 |
| Discussion of Changes ITS 3.4.12 Pages 1 through 4 | Discussion of Changes ITS 3.4.12 Page 1 |
| CTS markup for Specification 3.4.13 Page 1 of 1 | None |
| Discussion of Changes ITS 3.4.13 Page 1 | None |
| Discussion of Changes CTS 3/4.4.4 Page 1 | Discussion of Changes CTS 3/4.4.4 Page 1 |
| Discussion of Changes CTS 3/4.4.8 Page 1 | Discussion of Changes CTS 3/4.4.8 Page 1 |

| VOLUME 6, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| CTS markup for Specification 3.5.1 Page 2 of 6 through Page 3 of 6 | CTS markup for Specification 3.5.1 Page 2 of 6 through Page 3 of 6 |
| CTS markup for Specification 3.5.1 Page 1 of 6 through Page 6 of 6 | CTS markup for Specification 3.5.1 Page 1 of 5 through Page 5 of 5 |
| Discussion of Changes ITS 3.5.1 Pages 1 through 7 | Discussion of Changes ITS 3.5.1 Pages 1 through 6 |
| CTS markup for Specification 3.5.2 Page 1 of 5 through Page 5 of 5 | CTS markup for Specification 3.5.2 Page 1 of 4 through Page 4 of 4 |
| Discussion of Changes ITS 3.5.2 Pages 2 through 5 | Discussion of Changes ITS 3.5.2 Pages 2 through 4 |
| CTS markup for Specification 3.6.1.3 Page 4 of 21 | CTS markup for Specification 3.6.1.3 Page 4 of 21 |
| CTS markup for Specification 3.6.1.3 Page 15 of 21 | CTS markup for Specification 3.6.1.3 Page 15 of 21 |
| Discussion of Changes ITS 3.6.1.3 Page 4 | Discussion of Changes ITS 3.6.1.3 Page 4 |
| Discussion of Changes ITS 3.6.1.3 Page 7 | Discussion of Changes ITS 3.6.1.3 Page 7 |
| Discussion of Changes ITS 3.6.1.5 Page 1 | Discussion of Changes ITS 3.6.1.5 Page 1 |
| Discussion of Changes ITS 3.6.1.6 Page 2 | Discussion of Changes ITS 3.6.1.6 Page 2 |
| CTS markup for Specification 3.6.1.7 Page 1 of 2 | CTS markup for Specification 3.6.1.7 Page 1 of 2 |
| Discussion of Changes ITS 3.6.1.8 Page 2 | Discussion of Changes 3.6.1.8 Page 2 |
| Discussion of Changes ITS 3.6.2.1 Page 2 | Discussion of Changes 3.6.2.1 Page 2 |
| CTS markup for Specification 3.6.2.3 Page 1 of 1 | CTS markup for Specification 3.6.2.3 Page 1 of 1 |
| Discussion of Changes ITS 3.6.2.3 Pages 2 through 3 | Discussion of Changes ITS 3.6.2.3 Page 2 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 6, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| Discussion of Changes ITS 3.6.3.1 Page 2 | Discussion of Changes ITS 3.6.3.1 Page 2 |
| Discussion of Changes ITS 3.6.4.1 Pages 1 and 2 | Discussion of Changes ITS 3.6.4.1 Pages 1 and 2 |
| CTS markup for Specification 3.7.1 Page 1 of 3 | CTS markup for Specification 3.7.1 Page 1 of 3 |
| Discussion of Changes ITS 3.7.1 Pages 3 through 4 | Discussion of Changes ITS 3.7.1 Page 3 |
| Discussion of Changes ITS 3.7.5 Page 2 | Discussion of Changes ITS 3.7.5 Page 2 |
| Discussion of Changes ITS 3.7.7 Pages 1 and 2 | Discussion of Changes ITS 3.7.7 Pages 1 and 2 |
| Discussion of Changes CTS 3/4.7.4 Page 1 | Discussion of Changes CTS 3/4.7.4 Page 1 |
| Discussion of Changes CTS 3/4.7.5 Page 1 | Discussion of Changes CTS 3/4.7.5 Page 1 |
| Discussion of Changes CTS 3/4.7.8 Page 1 | Discussion of Changes CTS 3/4.7.8 Page 1 |
| CTS markup for Specification 3.8.1 Page 1 of 9 through Page 2 of 9 | CTS markup for Specification 3.8.1 Page 1 of 9 through Page 2 of 9 |
| Discussion of Changes ITS 3.8.1 Pages 5 through 17 | Discussion of Changes ITS 3.8.1 Pages 5 through 17 |
| CTS markup for Specification 3.8.2 Page 1 of 1 | CTS markup for Specification 3.8.2 Page 1 of 1 |
| Discussion of Changes ITS 3.8.2 Pages 3 through 4 | Discussion of Changes ITS 3.8.2 Page 3 |
| Discussion of Changes ITS 3.8.3 Page 2 | Discussion of Changes ITS 3.8.3 Page 2 |
| Discussion of Changes ITS 3.8.4 Pages 2 through 6 | Discussion of Changes ITS 3.8.4 Pages 2 through 6 |
| Discussion of Changes ITS 3.8.5 Page 2 | Discussion of Changes ITS 3.8.5 Page 2 |
| Discussion of Changes ITS 3.8.6 Page 2 | Discussion of Changes ITS 3.8.6 Page 2 |
| Discussion of Changes ITS 3.8.7 Page 2 | Discussion of Changes ITS 3.8.7 Page 2 |
| CTS markup for Specification 3.8.8 Page 1 of 1 | CTS markup for Specification 3.8.8 Page 1 of 1 |
| Discussion of Changes ITS 3.8.8 Page 3 | Discussion of Changes ITS 3.8.8 Page 3 |
| Discussion of Changes CTS 3/4.8.4.1 Page 1 | Discussion of Changes CTS 3/4.8.4.1 Page 1 |
| Discussion of Changes CTS 3/4.8.4.2 Page 1 | Discussion of Changes CTS 3/4.8.4.2 Page 1 |
| Discussion of Changes CTS 3/4.8.4.3 Page 1 | Discussion of Changes CTS 3/4.8.4.3 Page 1 |
| Discussion of Changes ITS 3.9.5 Page 2 | Discussion of Changes ITS 3.9.5 Page 2 |
| Discussion of Changes CTS 3/4.9.4 Page 1 | Discussion of Changes CTS 3/4.9.4 Page 1 |
| Discussion of Changes CTS 3/4.9.5 Page 1 | Discussion of Changes CTS 3/4.9.5 Page 1 |
| Discussion of Changes CTS 3/4.9.6 Page 1 | Discussion of Changes CTS 3/4.9.6 Page 1 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 6, CURRENT TECHNICAL SPECIFICATION (CTS) COMPARISON DOCUMENT | |
|---|---|
| DISCARD | INSERT |
| Discussion of Changes CTS 3/4.9.7 Page 1 | Discussion of Changes CTS 3/4.9.7 Page 1 |
| Discussion of Changes ITS 3.10.1 Page 1 | Discussion of Changes ITS 3.10.1 Page 1 |
| CTS markup for Specification 4.0 Page 1 of 8 through Page 8 of 8 | CTS markup for Specification 4.0 Page 1 of 7 through Page 7 of 7 |
| Discussion of Changes ITS 4.0 Pages 1 through 3 | Discussion of Changes ITS 4.0 Pages 1 through 2 |
| CTS markup for Specification 5.2 Page 1 of 5 | CTS markup for Specification 5.2 Page 1 of 5 |
| CTS markup for Specification 5.2 Page 5 of 5 | CTS markup for Specification 5.2 Page 5 of 5 |
| Discussion of Changes ITS 5.2 Pages 1 through 3 | Discussion of Changes ITS 5.2 Pages 1 through 3 |
| CTS markup for Specification 5.3 Page 1 of 1 | CTS markup for Specification 5.3 Page 1 of 1 |
| Discussion of Changes ITS 5.4 Page 1 | Discussion of Changes ITS 5.4 Page 1 |
| CTS markup for Specification 5.5 Page 15 of 21 through Page 18 of 21 | CTS markup for Specification 5.5 Page 15 of 21 through Page 18 of 21 |
| CTS markup for Specification 5.5 Page 21 of 21 | CTS markup for Specification 5.5 Page 21 of 21 |
| Discussion of Changes ITS 5.5 Page 2 | Discussion of Changes ITS 5.5 Page 2 |
| Discussion of Changes ITS 5.5 Pages 4 through 6 | Discussion of Changes ITS 5.5 Pages 4 through 6 |
| CTS markup for Specification 5.6 Page 2 of 9 | CTS markup for Specification 5.6 Page 2 of 9 |
| CTS markup for Specification 5.6 Page 7 of 9 through Page 9 of 9 | CTS markup for Specification 5.6 Page 7 of 9 through Page 9 of 9 |
| Discussion of Changes ITS 5.6 Pages 1 through 3 | Discussion of Changes ITS 5.6 Pages 1 through 3 |
| Discussion of Changes CTS 6.6 Page 1 | Discussion of Changes CTS 6.6 Page 1 |
| Discussion of Changes CTS 6.7 Page 1 | Discussion of Changes CTS 6.7 Page 1 |
| **VOLUME 7, NO SIGNIFICANT HAZARDS CONSIDERATION** | |
| DISCARD | INSERT |
| No Significant Hazards Evaluation ITS 3.4.2 Page 1 | No Significant Hazards Evaluation ITS 3.4.2 Page 1 |
| No Significant Hazards Evaluation ITS 3.4.3 Page 1 | No Significant Hazards Evaluation ITS 3.4.3 Pages 1 through 2 |
| No Significant Hazards Evaluation ITS 3.4.4 Pages 1 through 2 | No Significant Hazards Evaluation ITS 3.4.4 Pages 1 through 2 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 7, NO SIGNIFICANT HAZARDS CONSIDERATION | |
|---|---|
| DISCARD | INSERT |
| No Significant Hazards Evaluation ITS 3.4.5 Pages 1 through 2 | No Significant Hazards Evaluation ITS 3.4.5 Pages 1 through 5 |
| No Significant Hazards Evaluation ITS 3.4.6 Pages 1 through 2 | No Significant Hazards Evaluation ITS 3.4.6 Pages 1 through 3 |
| No Significant Hazards Evaluation ITS 3.4.7 Pages 1 through 3 | No Significant Hazards Evaluation ITS 3.4.7 Pages 1 through 3 |
| No Significant Hazards Evaluation ITS 3.4.8 Pages 1 through 3 | No Significant Hazards Evaluation ITS 3.4.8 Pages 1 through 6 |
| No Significant Hazards Evaluation ITS 3.4.9 Pages 1 through 6 | No Significant Hazards Evaluation ITS 3.4.9 Page 1 |
| No Significant Hazards Evaluation ITS 3.4.10 Page 1 | No Significant Hazards Evaluation ITS 3.4.10 Page 1 |
| No Significant Hazards Evaluation ITS 3.4.11 Page 1 | No Significant Hazards Evaluation ITS 3.4.11 Page 1 |
| No Significant Hazards Evaluation ITS 3.4.12 Page 1 | No Significant Hazards Evaluation ITS 3.4.12 Page 1 |
| No Significant Hazards Evaluation ITS 3.4.13 Page 1 | None |
| No Significant Hazards Evaluation ITS 3.5.1 Pages 3 through 9 | No Significant Hazards Evaluation ITS 3.5.1 Pages 3 through 8 |
| No Significant Hazards Evaluation ITS 3.6.2.3 Page 1 | No Significant Hazards Evaluation ITS 3.6.2.3 Page 1 |
| No Significant Hazards Evaluation ITS 3.7.1 Pages 1 through 4 | No Significant Hazards Evaluation ITS 3.7.1 Pages 1 through 3 |
| No Significant Hazards Evaluation ITS 3.8.1 Pages 3 through 23 | No Significant Hazards Evaluation ITS 3.8.1 Pages 3 through 22 |
| No Significant Hazards Evaluation ITS 3.8.2 Pages 1 through 4 | No Significant Hazards Evaluation ITS 3.8.2 Pages 1 through 3 |
| VOLUME 8, DEVIATIONS FROM NUREG-1434 (TECHNICAL SPECIFICATIONS) | |
| DISCARD | INSERT |
| 1.1-3 through 1.1-4 | 1.1-3 through 1.1-4 |
| 1.1-6 | 1.1-6 |
| Justification for Deviations Chapter 1.0 Page 1 | Justification for Deviations Chapter 1.0 Page 1 |
| 1.3-6 | 1.3-6 |
| 1.3-10 | 1.3-10 |
| 3.0-2 | 3.0-2 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 8, DEVIATIONS FROM NUREG-1434 (TECHNICAL SPECIFICATIONS) | |
|---|---|
| DISCARD | INSERT |
| 3.1-16 through 3.1-17 | 3.1-16 through 3.1-17 |
| 3.3-1 | 3.3-1 |
| 3.3-6 through 3.3-7 | 3.3-6 through 3.3-7 |
| Insert Page 3.3-19b | Insert Page 3.3-19b |
| Insert Page 3.3-19f | Insert Page 3.3-19f |
| 3.3-20 through 3.3-21 | 3.3-20 through 3.3-21 |
| 3.3-31 | 3.3-31 |
| 3.3-33 | 3.3-33 |
| 3.3-40 | 3.3-40 |
| 3.3-41 | 3.3-41 |
| 3.3-42 | 3.3-42 |
| 3.3-43 | 3.3-43 |
| 3.3-44 through 3.3-45 | 3.3-44 through 3.3-45 |
| 3.3-55 | 3.3-55 |
| 3.3-60 | 3.3-60 |
| 3.3-79 through Insert Page 3.3-80 | 3.3-79 through Insert Page 3.3-80 |
| 3.3-82 through 3.3-83 | 3.3-82 through 3.3-83 |
| 3.3-85 through Insert Page 3.3-85 | 3.3-85 through Insert Page 3.3-85 |
| Justification for Deviations Section 3.3 Pages 1 through 7 | Justification for Deviations Section 3.3 Pages 1 through 7 |
| 3.4-3 through 3.4-16 | 3.4-3 through 3.4-16 |
| 3.4-17 through 3.4-28 | 3.4-17 through 3.4-28 |
| Justification for Deviations Section 3.4 Pages 1 through 2 | Justification for Deviations Section 3.4 Pages 1 through 3 |
| 3.5-1 through 3.5-2 | 3.5-1 through 3.5-2 |
| 3.5-6 | 3.5-6 |
| 3.5-10 | 3.5-10 |
| Justification for Deviations Section 3.5 Pages 1 through 2 | Justification for Deviations Section 3.5 Page 1 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 8, DEVIATIONS FROM NUREG-1434 (TECHNICAL SPECIFICATIONS) | |
|---|---|
| DISCARD | INSERT |
| 3.6-11 | 3.6-11 |
| Insert Page 3.6-24e | Insert Page 3.6-24e |
| 3.6-33 | 3.6-33 |
| Justification for Deviations Section 3.6 Pages 6 through 7 | Justification for Deviations Section 3.6 Pages 6 through 7 |
| 3.7-2 through 3.7-3 | 3.7-2 through 3.7-3 |
| Justification for Deviations Section 3.7 Page 1 | Justification for Deviations Section 3.7 Page 1 |
| 3.8-2 through 3.8-3 | 3.8-2 through 3.8-3 |
| 3.8-5 | 3.8-5 |
| 3.8-9 | 3.8-9 |
| 3.8-10 | 3.8-10 |
| 3.8-14 | 3.8-14 |
| 3.8-22 | 3.8-22 |
| Justification for Deviations Section 3.8 Pages 1 through 5 | Justification for Deviations Section 3.8 Pages 1 through 5 |
| 3.10-1 | 3.10-1 |
| Justification for Deviations Section 3.10 Page 1 | Justification for Deviations Section 3.10 Page 1 |
| 5.0-2 | 5.0-2 |
| 5.0-5 | 5.0-5 |
| None | Insert Page 5.0-5 |
| 5.0-7 through 5.0-9 | 5.0-7 through 5.0-9 |
| 5.0-12 through 5.0-15 | 5.0-12 through 5.0-15 |
| 5.0-18 | 5.0-18 |
| 5.0-20 through 5.0-22 | 5.0-20 through 5.0-22 |
| Insert Pages 5.0-25a through 5.0-25b | Insert Pages 5.0-25a through 5.0-25b |
| Justification for Deviations Chapter 5.0 Pages 3 through 4 | Justification for Deviations Chapter 5.0 Pages 3 through 4 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 9, DEVIATIONS FROM NUREG-1434 (BASES) | |
|---|---|
| DISCARD | INSERT |
| B 2.0-3 | B 2.0-3 |
| B 2.0-5 through B 2.0-7 | B 2.0-5 through B 2.0-7 |
| B 3.0-2 | B 3.0-2 |
| B 3.0-7 | B 3.0-7 |
| B 3.1-33 through B 3.1-37 | B 3.1-33 through B 3.1.37 |
| B 3.1-47 | B 3.1-47 |
| B 3.2-1 through Insert Page B 3.2-2 | B 3.2-1 through Insert Page 3.2-2 |
| Insert Page B 3.2-4 through B 3.2-6 | Insert Page B 3.2-4 through B.2-6 |
| B 3.2-8 through Insert Page B 3.2-11 | B 3.2-8 through Insert Page B 3.2-11 |
| B 3.3-2 through B 3.2-3 | B 3.3-2 through B 3.2-3 |
| B 3.3-5 | B 3.3-5 |
| B 3.3-9 | B 3.3-9 |
| B 3.3-10 through B 3.3-11 | B 3.3-10 through B 3.3-11 |
| B 3.3-13 | B 3.3-13 |
| B 3.3-15 | B 3.3-15 |
| B 3.3-20 through B 3.3-22 | B 3.3-20 through B 3.3-22 |
| B 3.3-24 | B 3.3-24 |
| B 3.3-26 through B 3.3-28 | B 3.3-26 through B 3.3-28 |
| B 3.3-31 through B 3.3-32 | B 3.3-31 through B 3.3-32 |
| Insert Page B 3.3-52c through Insert Page B 3.3-52f | Insert Page B 3.3-52c through Insert Page B 3.3-52f |
| Insert Page B 3.3-52i through Insert Page B 3.3-52j | Insert Page B 3.3-52i through Insert Page B 3.3-52j |
| Insert Page B 3.3-52m through Insert Page B 3.3-52n | Insert Page B 3.3-52m through Insert Page B 3.3-52n |
| Insert Page B 3.3-52s | Insert Page B 3.3-52s |
| Insert Page B 3.3-52u | Insert Page B 3.3-52u |
| B 3.3-60 | B 3.3-60 |
| B 3.3-62 | B 3.3-62 |
| B 3.3-72 | B 3.3-72 |
| B 3.3-78 | B 3.3-78 |

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 9, DEVIATIONS FROM NUREG-1434 (BASES) | |
|---|---|
| DISCARD | INSERT |
| B 3.3-80 through B 3.3-82 | B 3.3-80 through B 3.3-82 |
| B 3.3-86 | B 3.3-86 |
| B 3.3-98 through B 3.3-99 | B 3.3-98 through Insert Page B 3.3-99 |
| B 3.3-102 through B 3.3-104 | B 3.3-102 through B 3.3-104 |
| B 3.3-106 | B 3.3-106 |
| B 3.3-109 through B 3.3-111 | B 3.3-109 through B 3.3-111 |
| B 3.3-113 through Insert B 3.3-113 | B 3.3-113 through Insert B 3.3-113 |
| B 3.3-117 | B 3.3-117 |
| B 3.3-119 through B 3.3-121 | B 3.3-119 through B 3.3-121 |
| B 3.3-123 through B 3.3-126 | B 3.3-123 through B 3.3-126 |
| B 3.3-128 | B 3.3-128 |
| B 3.3-175 through Insert Page B 3.3-176 | B 3.3-175 through Insert Page B 3.3-176 |
| B 3.3-235 through Insert Page B 3.3-237 | B 3.3-235 through Insert Page B 3.3-237a |
| B 3.3-245 through B 3.3-246 | B 3.3-245 through B 3.3-246 |
| B 3.4-1 through B 3.4-2 | B 3.4-1 through B 3.4-2 |
| Insert Page B 3.4-3 through B 3.4-4 | Insert Page B 3.4-3 through B 3.4-4 |
| Insert Page B 3.4-4b through B 3.4-17 | Insert Page B 3.4-4b through B 3.4-17 |
| B 3.4-18 through B 3.4-32 | B 3.4-18 through B 3.4-32 |
| B 3.4-33 through B 3.4-36 | B 3.4-33 through B 3.4-36 |
| B 3.4-37 through B 3.4-57 | B 3.4-37 through B 3.4-57 |
| B 3.4-58 through B 3.4-60 | B 3.4-58 through B 3.4-60 |
| B 3.4-61 through B 3.4-62 | B 3.4-61 through B 3.4-62 |
| Justification for Deviations Section 3.4 Page 1 | Justification for Deviations Section 3.4 Page 1 |
| VOLUME 10, DEVIATIONS FROM NUREG-1434 (BASES) | |
| DISCARD | INSERT |
| B 3.5-5 through B 3.5-8 | B 3.5-5 through B 3.5-8 |
| B 3.5-13 through Insert Page B 3.5-13 | B 3.5-13 |
| B 3.5-17 | B 3.5-17 |

[illegible]

## INSERT AND DISCARD INSTRUCTIONS

| VOLUME 10, DEVIATIONS FROM NUREG-1434 (BASES) | |
|---|---|
| DISCARD | INSERT |
| B 3.6-19 through B 3.6-22 | B 3.6-19 through B 3.6-22 |
| B 3.6-32 | B 3.6-32 |
| Insert Page B 3.6-47k | Insert Page B 3.6-47k |
| B 3.6-67 | B 3.6-67 |
| B 3.7-4 | B 3.7-4 |
| Justification for Deviations Bases Section 3.7 Page 1 | Justification for Deviations Bases Section 3.7 Page 1 |
| B 3.8-4 | B 3.8-4 |
| B 3.8-7 | B 3.8-7 |
| B 3.8-9 through B 3.8-10 | B 3.8-9 through B 3.8-10 |
| B 3.8-14 through B 3.8-16 | B 3.8-14 through B 3.8-16 |
| Insert Page B 3.8-16 through B 3.8-26 | Insert Page B 3.8-16 through B 3.8-26 |
| B 3.8-28 through B 3.8-30 | B 3.8-28 through B 3.8-30 |
| B 3.8-32 through B 3.8-34 | B 3.8-32 through B 3.8-34 |
| B 3.8-40 | B 3.8-40 |
| Insert Page B 3.8-42 | Insert Page B 3.8-42 |
| B 3.8-47 through B 3.8-48 | B 3.8-47 through B 3.8-48 |
| B 3.8-57 through Insert Page B 3.8-57 | B 3.8-57 through Insert Page B 3.8-57 |
| B 3.10-1 through B 3.10-3 | B 3.10-1 through B 3.10-3 |
| Justification for Deviations Bases Section 3.10 Page 1 | Justification for Deviations Bases Section 3.10 Page 1 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 1.0 | LA.1 | FRTP Definition | Bases 3.2.4 | 1.15 |
| | LA.2 | Pa | Bases 3.6.1.1 and 3.6.1.2 | 1.31a |
| 2.0 | LA.1 | Restore RPV water level | FSAR or LCS | 2.1.4 |
| 3.1.2 | LA.1 | Requirement to analyze changes in reactivity | Bases | 3.1.2.action a |
| 3.1.3 | LA.1 | Relocate way to disarm CRDs | Bases | 3.1.2.1.a.1.b.1 & 2, 3.1.2.1.b.2.a & b, 3.1.3.7.a.3.b |
| | LA.2 | How to determine position of rod | Bases | 3.1.3.7.a.1 & 2 |
| 3.1.4 | LA.1 | "Representative" sample of rods | Bases | 4.1.3.2.c |
| 3.1.5 | LA.1 | Disarm CRDs | Bases | 3.1.3.5.a.2.b.1 & 2 |
| | LC.1 | Leak and pressure, leak detection, and alarms for accumulators | FSAR or LCS | 4.1.3.5.b |
| 3.1.7 | LA.1 | SR "During Shutdown" | FSAR or LCS | 4.1.5.d |
| | LA.2 | SR Details | Bases | 4.1.5.d.1 |
| | LA.3 | SR Details | Bases | 4.1.5.d.1, 4.1.5.d.3 |
| | LA.4 | SLC-RV | IST Program | 4.1.5.d.2 |
| | LA.5 | Hi/Low Tank Alarms | Bases and FSAR | Figure 3.1.5-2 |
| 3/4.1.6 | LA.1 | Allowance to reduce feedwater | COLR | 3/4.1.6 |
| 3.2.1,2,3,4 | LA.1 | 15 Min = Prompt | Bases | 3.2.1.a, 3.2.3.a, 3.2.4.a, 3.2.2.a |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.2.4 | R.1 | APRM flow biased neutron flux-upscale C.R. block | LCS | 3.2.2 |
| | LA.2 | APRM GAFs | FSAR or LCS | 4.2.2.* |
| 3.3.1.1 | LA.1 | Details of SR | Bases | 4.3.1.2, Table 4.3.1.1-1 |
| | LA.2 | Put channel in trip | Bases | 4.3.1.3.* & ** |
| | LA.3 | Shorting links | FSAR or LCS | Table 3.3.1-1.a, Table 3.3.1-1.b, Table 3.3.1-1.* |
| | LA.4 | Required number of LPRMs | Bases | Table 3.3.1-1.2, Table 3.3.1-1.c |
| | LA.5 | Design details | FSAR | Table 3.3.1-1.5,6,8,9<br>Table 3.3.1-1.e, Table 3.3.1-1.d<br>Table 3.3.1-1.g, Table 3.3.1-1.i<br>Table 3.3.1-1.j |
| | LA.6 | Min thermal time constant | LCS | Table 4.3.1.1-1.h |
| | LA.7 | Trip Setpoint | FSAR or LCS | 2.2, Table 3.3.1.1-1 |
| 3.3.1.2 | LA.1 | SR Details | Bases | 4.3.7.6.c |
| | LA.2 | Details of operable | Bases | 3.9.2.a, 4.9.2.a.2 |
| | LA.3 | Shorting links | FSAR or LCS | 3.9.2.d, 4.9.2.d |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.3.2.1 | R.1 | Rod blocks for APRM, SRM, IRM, Scram discharge Volume and RRC Flow | LCS | Table 3.3.6-1, Table 4.3.6-1 Table 3.3.6.2 |
| | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.6, 3.3.6.a, Table 3.3.6-2.1, 3.3.4.1 |
| | LA.2 | Design detail | FSAR | Table 3.3.6-1 |
| | LA.3 | Details of SR | Bases | Table 3.3.6-1, 4.1.4.a,b,c |
| 3.3.2.2 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.9, Table 3.3.9-2 |
| 3.3.3.1 | R.1 | Specific accident monitoring instruments from Table | LCS | Table 3.3.7.5-1, Table 4.3.7.5-1 |
| | LA.1 | Alternate monitoring method | Bases | Table 3.3.7.5-1 |
| | LA.2 | SR Details | Bases | Table 4.3.7.5-1 |
| 3.3.3.2 | LA.1 | Remote Shutdown Panel Table | LCS and Bases | 3.3.7.4, 3.3.2.4.a, 4.3.7.4, Table 3.3.7.1-1, Table 4.3.7.4-1 |
| 3.3.4.1 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.4.2, 3.3.4.2.a, Table 3.3.4.2-2 |
| | LA.2 | EOC-RPT RTT | LCS | 3.3.4.2, 4.3.4.2.3, Table 3.3.4.2-3 |
| | LA.3 | Design detail | FSAR | Table 3.3.4.2-1 |
| 3.3.4.2 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.4.1, 3.3.4.1.a, Table 3.3.4.1-2 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.3.5.1 | R.1 | ADS inhibit | LCS | 1.3.5.2 |
| | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.3, 3.3.3.a, Table 3.3.3-2 |
| | LA.2 | SR Details | Bases | 4.3.3.2 |
| | LA.3 | Details design | Bases | Table 3.3.3-1, Table 3.3.3-2, Table 4.3.3.1-1 |
| 3.3.5.2 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.5, 3.3.5.a, Table 3.3.5-2 |
| | LA.2 | SR Details | Bases | 4.3.5.2 |
| | LA.3 | Design details | Bases | Table 3.3.5-1, Table 3.3.5-2 |
| 3.3.6.1 | R.1 | RCIC isolation signal | LCS | Table 3.3.2-1.h, Table 3.3.2-2.h, Table 4.3.2.1-1.h |
| | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.2, 3.3.2.a, Table 3.3.2-2 |
| | LA.2 | Action Details | Bases | 3.3.2.b.1, 3.3.2.b.2, 3.3.2.b.2.c |
| | LA.3 | Action Details | Bases | 3.3.2.* |
| | LA.4 | SR Details | Bases | 4.3.2.2 |
| | LA.5 | Design Details | Bases | Table 3.3.2-1 |
| | LA.6 | Condenser low vacuum | FSAR or LCS | Table 4.3.2.1-1 |
| | LA.7 | RHR-V-8 controls | FSAR or LCS | Table 3.3.2-1.i |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.3.6.2 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.2, 3.3.2.a, Table 3.3.2-2 |
| | LA.2 | Action Details | Bases | 3.3.2.b.1, 3.3.2.b.2, 3.3.2.b.2.b |
| | LA.3 | Action Details (which system to trip) | Bases | 3.3.2.* |
| | LA.4 | SR Details | Bases | 4.3.3.2 |
| | LA.5 | Design Details | Bases | Table 3.3.2-1 |
| 3.3.7.1 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.7.1-1 |
| 3.3.8.1 | LA.1 | Trip Setpoints | FSAR or LCS | 3.3.3, 3.3.3.a, Table 3.3.8.1-1 |
| | LA.2 | SR Details | Bases | 4.3.3.2 |
| | LA.3 | Design Details | Bases | Table 3.3.8.1-1 |
| | LA.4 | 120V basis for Trip Setpoint | FSAR | Table 3.3.8.1-1 |
| 3/4.3.7.1 | R.1 | Rad Monitoring Instrumentation | LCS | 3.3.7.1, 3.3.7.1-1, 4.3.7.1, Table 3.3.7.1-1 |
| 3/4.3.7.3 | R.1 | Met tower Instrumentation | FSAR or LCS | 3.3.7.3, 4.3.7.3, Table 3.3.7.3-1 |
| 3/4.3.7.7 | R.1 | TIPs | LCS | 3.3.7.7, 4.3.7.7 |
| 3/4.3.7.10 | R.1 | LPDS | FSAR or LCS | 3.3.7.10, 4.3.7.10 |
| 3/4.3.7.12 | R.1 | Explosive Gas | LCS | 3.3.7.12, 4.3.7.12, Table 3.3.7.12-1 |
| 3/4.3.8 | R.1 | TG overspeed | LCS | 3.3.8, 4.3.8.1, 4.3.8.2 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.4.1 | LA.1 | Action Details, 15 minutes | Bases | 3.4.1.1.2 |
| | LA.2 | Details on how to exit region | Bases | 3.4.1.1.2, 3.2.7, 3.2.7.b, 3.2.8.a, 3.2.8.b |
| | LA.3 | Details on single loop limits | FSAR or LCS | 3.4.1.1.3.a, 3.4.1.1.3.d, 4.4.1.1.1.a, 4.4.1.1.1.b |
| | LA.4 | Power/Flow map | COLR | 3.4.1.1.2, 4.4.1.1.1.c, Figure 3.4.1.1-1, 3.2.6, 4.2.6, Figure 3.2.6-1, 3.2.7, Figure 3.2.7-1, 3.2.8, Figure 3.2.8-1 |
| | LA.5 | Action Details | Bases | 3.2.6 |
| | LA.6 | Stability Monitor System Details | Bases | 3.2.7, 3.2.7.a, 3.2.8, 3.2.8.a |
| | LA.7 | Action Details | Bases | 3.2.7.a, 3.2.7.b, 3.2.8.a, 3.2.8.b |
| | LA.8 | Speed Control Surveillance | FSAR | 4.4.1.1.3 |
| 3.4.3 | LA.1 | Lift Setpoint Details | Bases | 3.4.2.* |
| 3.4.4 | LA.1 | Lift Setpoint Details | Bases | 3.4.2.* |
| 3.4.5 | LA.1 | SR Details | Bases | 4.4.3.2.1.a & b |
| 3.4.6 | LA.1 | PIV Table of equipment | LCS | 3.4.3.2.e, 4.4.3.2.2, Table 3.4.3.2-1 |
| | LA.2 | IST Frequency | IST Program | 4.4.3.2.2.a |
| | LC.1 | PIV high/Low interface instruments | LCS | 3.4.3.2.Action d, 4.4.3.2.3, Table 3.4.3.2-2 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.4.8 | LA.1 | Offgas isotope | FSAR or LCS | Table 4.4.5-1 |
| 3.4.9 | LA.1 | OPERABLE RHR SDC Details | Bases | 3.4.9.1.a & b |
| 3.4.10 | LA.1 | OPERABLE RHR SDC Details | Bases | 3.4.9.2.a & b |
| 3.4.11 | LA.1 | Details of Surveillance | Bases | 4.4.6.1.1, 4.4.6.1.2 |
| | LA.2 | Thermal Power and RRC Flow Details | Bases | 4.4.1.1.2.*** |
| | LA.3 | SLO limits | FSAR or LCS | 3.4.1.4.b, 3.4.1.4.action |
| 3/4.4.4 | R.1 | Rx chem | LCS | 3.4.4, 4.4.4, Table 3.4.4-1 |
| 3/4.4.8 | R.1 | Structure integrity | FSAR | 3.4.8, 4.4.8 |
| 3.5.1 | LA.1 | OPERABILITY Details | Bases | 3.5.1.a.1 & 2, 3.5.1.b.1, 3.5.1.c |
| | LA.2 | SR Details | Bases | 4.5.1.a.1 & 2, 4.5.1.b.1-3 4.5.1.c, 4.5.1.d, 4.5.1.e.3.b |
| | LC.1 | Instrumentation requirement | FSAR or LCS | 4.5.1.e.2, 4.5.1.e.3.c |
| | LC.2 | ADS nitrogen capacity | FSAR or LCS | 4.5.1.e.3.d |
| 3.5.2 | LA.1 | OPERABILITY Details | Bases | 3.5.2, 3.5.3.d.4 |
| | LA.2 | CST level/volume correlations | Bases | 3.5.3, 3.5.3.b.3 |
| 3.5.3 | LA.1 | OPERABILITY Details | Bases | 3.7.3 |
| | LA.2 | SR Details | Bases | 4.7.3.a.1, 4.7.3.a.3, 4.9.3.c.1, 4.7.3.c.3 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.6.1.1 | LA.1 | PCIV list of valves for 3.6.3.1 | LCS | 3.6.1.2.b, 3.6.1.2.AWb, 3.6.1.2.ARb, 4.6.1.2.* |
| 3.6.1.2 | LA.1 | Details of OPERABLE air lock | Bases | 3.6.1.3.b |
| 3.6.1.3 | LA.1 | PCIV list of valves | LCS | 3.6.3, 3.6.3.a, 3.6.3.b, 3.6.3.1, 4.6.3.2, 4.6.3.3, 4.6.3.4, Table 3.6.3.1, 4.6.1.1.b |
| | LA.2 | Explosive squibs for TIPs | Bases | 4.6.3.5.b |
| | LA.3 | Administrative Control on locked PCIV | FSAR or LCS | 4.6.1.1.** |
| | LA.4 | Leak rate and test pressure | Bases | 3.6.1.2.d |
| 3.6.1.4 | LA.1 | SR Details | Bases | 4.6.1.7 |
| 3.6.1.5 | R.1 | Suppression pool spray capability | LCS | 3.6.2.2.Action a & b, 4.6.2.2, 4.6.2.2.b |
| | LA.1 | OPERABILITY Details | Bases | 3.6.2.2 |
| | LA.2 | SR Details | Bases | 4.6.2.2.c |
| 3.6.1.6 | LA.1 | OPERABILITY Details | Bases | 3.6.4.2 |
| | LA.2 | Visual Inspection | FSAR | 4.6.4.2.b.2.b |
| 3.6.1.7 | LA.1 | Design details | Bases | 3.6.4.1 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.6.1.8 | LA.1 | Design Details | Bases | 3.6.1.4 |
| | LA.2 | SR Details | Bases | 4.6.1.4.a.1 & 2, 4.6.1.4.c |
| | LA.3 | Repeated IST Details | IST Program | 4.6.1.4.b |
| | LC.1 | MSLC instrumentation | FSAR or LCS | 4.6.1.4.d |
| 3.6.2.1 | LA.1 | How to reduce SP temp details | FSAR or LCS | 3.6.2.1.Action b.2.b |
| 3.6.2.2 | LA.1 | Pool Volumes vs Level Details | Bases | 3.6.2.1.a.1, 3.5.3.a |
| 3.6.2.3 | LA.1 | OPERABILITY Details | Bases | 3.6.2.3 |
| 3.6.3.1 | LA.1 | Design Details | Bases | 3.6.6.1 |
| | LA.2 | SR Details | Bases | 4.6.6.1.b.2, 4.6.6.1.b.3, 4.6.6.1.b.4 |
| | LC.1 | Instrumentation | FSAR or LCS | 4.6.6.1.b.1 |
| 3.6.4.1 | LA.1 | Verify blow out panels | FSAR or LCS | 4.6.5.1.b.1 |
| 3.6.4.2 | LA.1 | Secondary containment isolation equipment | LCS | 3.6.5.2, 3.6.5.2.Action, Table 3.6.5.2-1 |
| 3.6.4.3 | LA.1 | Design Details | Bases | 3.6.5.3 |
| | LA.2 | SR Details | Bases | 4.6.5.3.a |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.7.1 | LA.1 | OPERABILITY Details | Bases | 3.7.1.1, 3.7.1.3 |
| | LA.2 | SW in MODE 4 & 5 is a support system for ECCS, DG, SDC and other systems required in MODE 4, 5. | 3.5.2 Bases, 3.8.2 Bases and others | 3.7.1.1, 3.7.1.1.Action b, c & d, 3.7.1.1.*, 3.7.1.3, 3.7.1.3.Action b & c, 3.7.1.3.* |
| 3.7.2 | LA.1 | OPERABILITY Details | Bases | 3.7.2.1 |
| | LA.2 | OPERABILITY in MODE 4 & 5 moved to supported systems | 3.8.2 Bases | 3.7.1.2, 3.7.1.2.Action |
| 3.7.3 | LA.1 | Design Details | Bases | 3.7.2 |
| | LA.2 | SR Details | Bases | 4.7.2.b |
| 3.7.5 | LA.1 | SR Details | Bases | 3.11.2.7, 4.11.2.7.2, 4.11.2.7.2.b |
| | LA.2 | Monitor radioactivity rate | ODCM | 4.11.2.7.1 |
| 3.7.6 | LA.1 | SR details. | Bases | 4.7.9.b.1, 4.7.9.b.2 |
| | LA.2 | RTT for bypass system | LCS | 4.7.9.b.3 |
| 3.7.7 | LA.1 | Crane operations w/loads | FSAR or LCS | 3.9.9.Action |
| | LA.1 | Load analysis & controls | FSAR | 3.9.9.Action |
| | LA.2 | ACTION details | Bases | 3.9.9.Action |
| 3/4.7.4 | LA.1 | Snubber Program | LCS | 3.7.4, 4.7.4, Table 4.7-1, Figure 4.7-1 |
| 3/4.7.5 | R.1 | Sealed Sources | LCS | 3.7.5, 4.7.5.1, 4.7.5.2, 4.7.5.3 |
| 3/4.7.8 | R.1 | Area Temperature Monitoring | LCS | 3.7.8, 4.7.8, Table 3.7.8-1 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.8.1 | LA.1 | OPERABILITY and Design Details | Bases | 3.8.1.1.a, 3.8.1.1.b |
| | LA.2 | DG test frequency - must implement RG 1.160 in 90 days | FSAR or LCS | 4.8.1.1.2.a, Table 4.8.1.1.2-1 |
| | LA.3 | Identify specific start signals | FSAR or LCS | 4.8.1.1.2.a.4, 4.8.1.1.2.a.6 |
| | LA.4 | Maintenance inspection | FSAR | 4.8.1.1.2.e.1 |
| | LA.5 | Reject load size | Bases | 4.8.1.1.2.e.2, 4.8.1.1.2.e.9 |
| | LA.5 | Auto connected load size | FSAR | 4.8.1.1.2.e.2, 4.8.1.1.2.e.9 |
| | LA.6 | Loading logic | Bases | 4.8.1.1.2.e.4.2, 4.8.1.1.2.e.6.a.2, 4.8.1.1.2.e.6.b.2 |
| | LA.7 | Starting and maintaining DG | FSAR or LCS | 4.8.1.1.2.e.8 |
| | LA.8 | Test lock out feature | FSAR or LCS | 4.8.1.1.2.e.13 |
| 3.8.2 | LA.1 | Crane operations | FSAR or LCS | 3.8.1.2.Action a |
| 3.8.3 | LA.1 | 10 year testing and cleaning of storage tank | FSAR | 4.8.1.1.2.g |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.8.4 | LA.1 | OPERABILITY Details | Bases | 3.8.2.1.a.1, 2, 4 & 5, 3.8.2.1.b.1 & 3, 3.8.2.1.c |
| | LA.2 | 24 volt DC requirement | LCS | 3.8.2.1.a.3 & 6, 3.8.2.1.b.2 & 4, 4.8.2.1, 4.8.2.1.b, 4.8.2.1.b.3, 4.8.2.1.c.4.1, 4.8.2.1.d.2 |
| | LA.4 | Required loads | Bases | 4.8.2.1.c.4.2 |
| | LA.5 | Details of DC loads and Service duration | FSAR | 4.8.2.1.d.1 & 2 |
| | LA.6 | Degraded battery | Bases | 4.8.2.1.f |
| 3.8.5 | LA.1 | OPERABILITY Details | Bases | 3.8.2.2, 3.8.2.2.a.1, 2, 4 & 5, 3.8.2.2.b.1 & 3, 3.8.2.2.c |
| | LA.2 | 24 VDC Requirement | LCS | 3.8.2.2.a.3 & 6, 3.8.2.2.b.2 & 4 |
| 3.8.6 | LA.1 | 24 VDC Requirement | LCS | 4.8.2.1, 4.8.2.1.b, 4.8.2.1.b.3 |
| | LA.2 | Details of "representative" | Bases | 4.8.2.1.b.3 |
| 3.8.7 | LA.1 | OPERABILITY and Design Details | Bases | 3.8.3.1, 3.8.3.1.a, 3.8.3.1.b.1.a - g & i, 3.8.3.1.b.2.a - e, 3.8.3.1.b.3 |
| | LA.2 | 24 VDC Distribution | LCS | 3.8.3.1.b.1.h, 3.8.3.1.b.2.f |
| | LA.3 | SR Details | Bases | 4.8.3.1 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3.8.8 | LA.1 | OPERABILITY and Design Details | Bases | 3.8.3.2.a.1-3, 3.8.3.2.b.1-3 |
| | LA.2 | SR Details | Bases | 4.8.3.2 |
| | LA.3 | 24 VDC Distribution | LCS | 3.8.3.2.b.1.h, 3.8.3.2.6.2.f |
| 3/4.8.4.1 | R.1 | De-energize circuits | LCS | 3.8.4.1, 4.8.4.1 |
| 3/4.8.4.2 | R.1 | Over current protective devices | LCS | 3.8.4.2, 4.8.4.2, Table 3.8.4.2-1 |
| 3/4.8.4.3 | R.1 | Thermal overloads | LCS | 3.8.4.3, 4.8.4.3, Table 3.8.4.3-1 |
| 3.9.5 | LC.1 | Accumulator instrumentation indication/alarm SR and Operable | FSAR or LCS | 4.1.3.5.b.1 |
| 3.9.6 | LA.1 | Place fuel in safe condition | Bases | 3.9.8.Action |
| 3.9.7 | LA.1 | Place fuel and rods in safe condition | Bases | 3.9.8.Action |
| 3.9.8 | LA.1 | OPERABILITY Details | Bases | 3.9.11.1.a & b |
| | LA.2 | SR Details | Bases | 4.9.11.1 |
| 3.9.9 | LA.1 | OPERABILITY Details | Bases | 3.9.11.2.a & b |
| | LA.2 | SR Details | Bases | 4.9.11.2 |
| 3/4.9.4 | R.1 | 24 hr. decay time | FSAR or LCS | 3.9.4, 4.9.4 |
| 3/4.9.5 | R.1 | Control room to refuel platform communications | FSAR or LCS | 3.9.5, 4.9.5 |
| 3/4.9.6 | R.1 | Refuel Platform OPERABILITY | LCS | 3.9.6, 4.9.6 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 3/4.9.7 | R.1 | Crane travel | LCS | 3.9.7, 4.9.7, Figure 3.9.7-1 |
| 3.10.1 | LA.1 | Max Coolant temperature | FSAR or LCS | 3.10.7 |
| 3.10.2 | LA.1 | Details of actions for verification | Bases | Table 1.2, 4.9.1.2.* |
| 3.10.4 | LA.1 | Details to disarm CRD | Bases | 3.9.10.1.d, 4.9.10.1.d |
| 3.10.5 | LA.1 | Details to disarm CRD | Bases | 3.9.10.1.d, 4.9.10.1.d |
| 4.0 | LA.1 | Details of unrestricted area | FSAR | 5.1.2, 5.1.3, 5.4 |
| | LA.2 | Details of design for Primary and secondary containment and RCS | FSAR | 5.2, 5.3.1 |
| | LA.3 | Met tower location/design | FSAR | 5.5 |
| 5.2 | LA.1 | Reporting requirement for QA | FSAR | 6.2.1.e |
| | LA.2 | Minimum shift crew requirement | FSAR | 6.2.2.a, Table 6.2.2-1 |
| | LA.3 | Chemistry personnel requirement | FSAR | 6.2.2.c, 6.2.2.* |
| | LA.3 | Fire brigade requirement | Fire Protection Plan (FSAR) | |
| | LA.4 | SRO to supervise core ALTS | FSAR or LCS | 6.2.2.d |
| | LA.5 | Crew position license requirement | FSAR | 6.2.2.f |
| | LA.6 | NSAD requirement | OQAPD | 6.2.3 |
| 5.3 | LA.1 | Operator qualification requirements | FSAR | 6.3.1 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| 5.4 | LA.1 | Details for Plant Procedures and deviation reviews | OQAPD | 6.8.2, 6.8.3 |
| 5.5 | LA.1 | In plant rad monitoring program | FSAR | 6.8.4.B |
| | LA.2 | REMP | ODCM | 6.8.4.e |
| | LA.3 | Component cyclic, transients | FSAR | 5.7.1, Table 5.7.1-1 |
| | LA.4 | ISI | ISI Program | 4.0.5, 4.0.5.a, 4.0.5.b, 4.0.5.c, 4.0.5.d, 4.0.5.f |
| | LA.5 | IST | IST Program | 4.0.5.a |
| | LA.6 | VFTP implementation | FSAR or LCS | Page 3/4 6-42.b.2, Page 3/4 6-42.c, Page 3/4 7-6.c.2, Page 3/4 7-6.d |
| | LA.7 | Stored radioactive liquid limits contained in CTS 3/4.11.1.4 and explosive gas limits contained in 3/4.11.2.6. | ODCM and FSAR or LCS | 3.11.1.4, 4.11.1.4, 3.11.2.6, 4.11.2.6 |
| | LA.8 | DG fuel oil ASTMs | Bases 3.8.3 | Page 3/4 8-4.c, Page 3/4 8-4.c.1, Page 3/4 8-4.c.1.a, Page 3/4 8-4.c.1.b, Page 3/4 8-4.c.1.c, Page 3/4 8-4.c.1.d, Page 2/4 8-4.c.2, Page 3/4 8-4.d |
| 5.6 | LA.1 | Start up report | FSAR | 6.9.1.1, 6.9.1.2, 6.9.1.3 |
| CTS 6.4 | LA.1 | Training requirements | FSAR | 6.4 |

## RELOCATED ITEMS AND CONTROL PROCESS

| Spec # | DOC | Comments | Proposed Location (DOC, Rev C) | CTS |
|---|---|---|---|---|
| CTS 6.5 | LA.1 | POC, CNSRB, audits, etc. | OQAPD | 6.5 |
| CTS 6.6 | LA.1 | Reportable events | FSAR or LCS | 6.6.1.a |
| | LA.2 | Event review requirement | OQAPD | 6.6.1.b |
| CTS 6.7 | LA.1 | Notifications of Safety Limit violation | FSAR or LCS | 6.7.1 |
| CTS 6.10 | LA.1 | Record retention | OQAPD | 6.10 |
| CTS 6.11 | LA.1 | Rad protection program | FSAR | 6.11 |
| CTS 6.13 | LA.1 | Process Control Program | FSAR | 6.13, 1.33 |

## RELOCATED ITEMS AND CONTROL PROCESS

### CONTROL PROCESS

| DOCUMENT | PROCESS |
|---|---|
| Bases | ITS 5.5, Bases Control Program |
| COLR | 10 CFR 50.59 |
| FSAR | 10 CRF 50.59 |
| ISI and IST Programs | 10 CFR 50.59 and 50.55a(f) |
| LCS Manual | 10 CFR 50.59 |
| ODCM | ITS 5.5 |
| OQAPD | 10 CFR 50.59 and 50.54(a)(3) |

The following analysis provides a response to the NRC request concerning the capability of the emergency diesel generator (EDG) excitation system to successfully reestablish the offsite source to a loaded safety bus when initially running isolated supplying its automatically connected accident loads. The information is provided for all three standby generators at WNP-2.

The excitation system of each EDG was evaluated by examining previous test data, together with available generator manufacturer design capability curves, and comparing performance needed when synchronizing a EDG initially running isolated with (1) calculated maximum automatically connected accident load or (2) test loads used to satisfy current Technical Specification (CTS) surveillance requirement (SR) 4.8.1.1.2.e.10, against the design ratings of the machines.

The Supply System has concluded that the results indicate that each emergency generator is capable within its excitation system ratings to synchronize a loaded safety bus back to a preferred offsite source.

**Test Data:**

The CTS SR 4.8.1.1.2.e.10 requires the demonstration of the EDG capability to synchronize with the offsite power source while the generator is loaded with its emergency loads (to simulate restoration of offsite power), to transfer the loads to the offsite power source and to be returned to standby status.

The following tabulation of the load on the safety bus prior to synchronizing to the offsite source was obtained from the test records for Plant Procedures (PPMs) 7.4.8.1.1.2.7, 7.4.8.1.1.2.7A and 7.4.8.1.1.2.8. These procedures are performed to satisfy existing CTS SR 4.8.1.1.2.e.10. The power factor (pf) is calculated from the test KW and KVAR values. In each test, the load was successfully restored to the offsite power supply.

| EDG | EDG-1 | | | EDG-2 | | | EDG-3 (HPCS) | | |
|---|---|---|---|---|---|---|---|---|---|
| Test PPM | 7.4.8.1.1.2.7 | | | 7.4.8.1.1.2.7A | | | 7.4.8.1.1.2.8 | | |
| Load | KW | KVAR | PF | KW | KVAR | PF | KW | KVAR | PF |
| Year: | | | | | | | | | |
| 1990 | 3500 | 1750 | .89 | 3100 | 1650 | .88 | 2400 | -- | -- |
| 1991 | 3400 | 1700 | .89 | 3100 | 1650 | .88 | 2420 | 1050 | .917 |
| 1992 | 3200 | 1700 | .88 | 2900 | 1500 | .888 | 2350 | 1020 | .917 |
| 1993 | 3400 | -- | -- | 3000 | -- | -- | 2400 | 1080 | .912 |
| 1994 | 3400 | 1700 | .89 | -- | -- | -- | 2260 | 1000 | .914 |
| 1995 | 3500 | 1750 | .89 | 2900 | 1700 | .86 | 2400 | 1050 | .916 |
| 1996 | 3400 | 1700 | .89 | test next cycle | | | 2400 | 1010 | .921 |

An evaluation of test results for a typical year (1995) together with projected excitation current and estimated safety bus voltage (converted from measurements of the 230 kV offsite source taken during the weekly offsite station power alignment checks and shown in Table 1) was performed to assess excitation system operating margin when synchronizing a loaded safety bus to an offsite source. This evaluation was repeated for the case where the EDG is loaded with an emergency load prior to synchronizing to an offsite source restored post accident.

The table below was tabulated using the test values from the 1995 tests for the KW and KVAR values. The KVA, pf and current values were calculated from these values. The per unit (pu) values listed for each parameter are based on the generator rated parameters as listed in Table 2. The exciter current listed was obtained from the generator manufacturer's V curves for the indicated load current on the generator (see Figure 1). These values should be close to actual because when the EDG is run isolated carrying these loads, the terminal voltage will be held close to 1.0 pu by the voltage regulator.

| EDG | EDG-1 | | EDG-2 | | EDG-3 | |
|---|---|---|---|---|---|---|
| KVA | 3913.12 | (.673 pu) | 3361.54 | (.578 pu) | 2619.64 | (.735 pu) |
| KW | 3500 | (.752 pu) | 2900 | (.623 pu) | 2400 | (.841 pu) |
| KVAR | 1750 | (.50 pu) | 1700 | (.487 pu) | 1050 | (.491 pu) |
| power factor (pf) | .894 | | .863 | | .916 | |
| I phase (amps) | 543 | (.673 pu) | 466.5 | (.578 pu) | 363.5 | (.735 pu) |
| I exciter (amps) | 118 * | (.93 pu) | 114 * | (.948 pu) | ** | |

* approximation based on generator manufacturer V curve,
** generator manufacturer V curve not available

The table below shows the expected exciter current requirement to produce 1.0 pu voltage when the EDG is running isolated with its automatically connected accident loads obtained from Calculation E/I-02-87-07, Appendix F. The required excitation current is obtained from the manufacturer's V curves by extrapolation between the appropriate pu load curves (see Figure 2).

| EDG | EDG-1 | | EDG-2 | | EDG-3 (HPCS) | |
|---|---|---|---|---|---|---|
| KVA | 4888.3 | (.841 pu) | 4551.9 | (.783 pu) | 2850.9 | (.800 pu) |
| KW | 4383.1 | (.943 pu) | 4046.3 | (.870 pu) | 2610 | (.916 pu) |
| KVAR | 2164.3 | (.620 pu) | 2085.0 | (.598 pu) | 1147 | (.537 pu) |
| power factor (pf) | .897 | | .889 | | .9155 | |
| I phase (amps) | 677.6 | (.840 pu) | 631.0 | (.782 pu) | 395.6 | (.800 pu) |
| I exciter (amps) | 129 * | (.930 pu) | 126 * | (.913 pu) | ** | |

* approximation based on generator manufacturer V curve
** generator manufacturer V curve not available

Note: The manufacturer's V curves show the relationship of generator field current to pu phase current and power factor (pf) at rated voltage. From the above data, plotting the pu phase current on the V curve for the two operating cases and extrapolating between the pu load curves shows, at rated voltage, an approximate value of excitation current to support this load.

**Analysis of EDG Test Data:**

Each EDG, running isolated on the loaded safety bus, must be capable of raising the voltage on the bus to match the offsite network voltage, and then synchronizing to the offsite network to restore the offsite source. To determine the safety bus voltage level required prior to synchronizing a loaded safety bus to an offsite power supply, records of the weekly measurements of the 230 kV network voltage per PPM 7.4.8.1.1.1.1 were tabulated and converted to the approximate voltage at the safety bus (see Table 1). As shown, the offsite network may be operating as high as 242 kV. The preferred offsite source transformer has a minus 2.5 percent off-load tap setting, so the open circuit voltage at the 4.16 kV secondary (Y winding) could be as high as 4.486 kV (or 1.078 pu rated voltage). Assuming minimum voltage drop through the upstream medium voltage buses that subfeed the safety buses during testing or post accident distribution system loading conditions, the voltage on the safety bus may have to be raised to this level in order to synchronize with the offsite network. To match the bus voltage to synchronize with the offsite power network, the EDG would have to be over-excited to a field current beyond that required for operation at 1.0 pu voltage on the safety bus. The EDG loading may have to be decreased or the offsite power network voltage decreased to stay within the rating or control range of the excitation system.

**EDG-1 and EDG-2:**

From the data tabulated, it has been estimated that EDG-1 and EDG-2 will need approximately 114 to 129 amps DC field current running isolated on the safety bus when partially loaded with either simulated test loads or calculated maximum automatically connected accident loads at 1.0 pu voltage on the safety bus. These loads are less than the full rated load of the generator. Using the estimated excitation current at a particular load running isolated on the safety bus, the required field current needed to run the loaded bus at an elevated voltage needed to synchronize with the offsite power network can be estimated. The generator manufacturer saturation curve for DG-1 and DG-2, shows the EDGs need about eight to 11 additional amps of field current to raise the voltage from 1.0 pu to 1.08 pu at full rated generator load and power factor. Since the generator will not be run at full load or the rated power factor (the parameters for which the saturation curve is derived), the EDG will actually require less exciter current to raise the bus voltage to 1.08 pu. Estimated field current needed to synchronize a loaded safety bus to the offsite network for the two cases is shown as follows:

Excitation to Synchronize Calculated Maximum Automatically Connected Accident Loads

| EDG | EDG-1 | EDG-2 |
|---|---|---|
| KVA | 4888.3 | 4551.9 |
| KW | 4383.1 | 4046.3 |
| KVAR | 2164.3 | 2085.0 |
| power factor | .897 | .889 |
| I exciter, with EDG isolated at 1.0 pu Voltage (from Figure 2) | ~129 | ~126 |
| I exciter, with EDG isolated at 1.08 pu Voltage, prior to synchronizing (from Figure 3) | ~140, (figure 3, curve A) | ~136 |

Excitation to Synchronize PPM 7.4.8.1.1.2.8 Test Loads (1995)

| EDG | EDG-1 | EDG-2 |
|---|---|---|
| KVA | 3913.12 | 3361.54 |
| KW | 3500 | 2900 |
| KVAR | 1750 | 1700 |
| power factor | .894 | .863 |
| I exciter, with EDG isolated at 1.0 pu Voltage (Figure 1) | ~118 | ~114 |
| I exciter, assuming EDG is isolated at 1.08 pu Voltage, prior to synchronizing (Figure 3) | ~127 | ~122 |

With calculated maximum automatically connected (steady state) accident loads running on the safety bus, EDG-1 may need as much as 140 amps DC field current while DG-2 may need about 136 amps DC field current to restore the offsite power supply, under the highest expected grid conditions (Figure 3). This estimate also shows available margin to allow for meter accuracy and any differences between calculated performance characteristics and equipment ratings. Curve B on Figure 3 shows the estimated margin to the exciter short time rating of 149 amps

The field current rating of the EDG-1 and EDG-2 static exciters is 142.4 amps DC continuous at rated load, 149 amps DC (104.6% of rated) for 30 minutes and 395 amps DC field transient or field forcing current to start large motors. Since these ratings are based on thermal limitations associated with the winding insulation system, they can be adjusted using an $i^2t$ relationship (current squared multiplied by time). This means that for incrementally higher field currents, the allowable duration would decrease. If the EDG is operated within ratings and adheres to an $i^2t$ relationship for short periods of overload, no accelerated loss of life is expected for the field winding insulation or exciter line components. Therefore, the generator field current needed to raise bus voltage to enable synchronization of a loaded safety bus with the offsite source is within the capability and rating of the EDG-1 and EDG-2 excitation systems.

**EDG-3:**

The HPCS standby generator and excitation system was manufactured by General Electric in 1972. In addition to its continuous rating of 100 amps DC, the field winding has a field forcing (or short time) rating of 450 amps (450% of the continuous rating) for two minutes in any 30 minute period. This is equivalent to a short time rating of 116 amps (116% of the continuous rating using the $i^2t$ relationship) for 30 minutes. The excitation system for EDG-3 is less limiting than EDG-1 and EDG-2 which have a transient capability of 395 amps DC (277% of the continuous rating) for large motor starts and a short time rating of 149 amps DC (104.6%) for 30 minutes.

The generator manufacturer saturation curve and V curve for DG-3 are not currently available to allow a similar evaluation of unit performance during synchronizing with the offsite source. However, EDG-3 is typically loaded to about 73% of its KVA rating with the largest load (HPCS-P-1) during performance of the testing to satisfy CTS SR 4.8.1.1.2.e.10. There is no history of problems experienced when synchronizing EDG-3 running isolated on a loaded safety bus (E-SM-4) to the offsite source during this test.

When loaded against the grid at a similar load level, recorded field current averages only 60 amps (.64 pu) out of 94 amps needed for rated load and power factor (from the annual 24 hour endurance load run test data).

**Conclusions:**

This analysis shows that EDG-1 and EDG-2 have sufficient operating margin and capability, within ratings, to:

1) synchronize with the offsite power source while the generator is loaded with its emergency (automatically connected maximum steady state) loads upon restoration of offsite power (post accident);

2) transfer the loads to the offsite source; and

3) be returned to standby status.

For DG-3, the surveillance test data for SR 4.8.1.1.2.e.10 shows the unit is capable, within ratings, of:

1) synchronizing with the offsite power source while the generator is loaded with emergency loads upon restoration of offsite power;

2) transferring the emergency load to the offsite source; and

3) being returned to standby status.

Results also indicate that under worst case high voltage grid conditions with the EDG running isolated on the safety bus for test or with postulated maximum automatically connected accident load conditions, the EDG exciters may require field current in excess of full load continuous rating (but within its short time ratings) in order to synchronize to the offsite source. Therefore, appropriate procedures will be revised to include guidance to operators to avoid excessive overloading of the static exciters when synchronizing a loaded safety bus to the offsite source.

**Attachments:**

| | |
|---|---|
| Table 1 | Measurements of the 230 KV Offsite Source Voltage |
| Table 2 | EDG Ratings |
| Figure 1 | EDG-1 and EDG-2 1995 Test Load Field Current (V Curve) |
| Figure 2 | EDG-1 and EDG-2 Accident Load Field Current (V Curve) |
| Figure 3 | Excitation with EDG Isolated at 1.08 pu Voltage Prior to Synchronizing the Standby Generator (Saturation Curve) |

**Table 1**
**"Measurements of the 230 KV Offsite Source Voltage"**

| Date, time (plant status) | 230 KV Offsite Source Voltage (From PPM 7.4.8.1.1.1.1) (note: E-TR-S has a minus 2.5% tap) | Voltage in KV and Per Unit on Generator Rated Voltage. (Determined by using transformer turns ratio to give secondary voltage at no load.) |
|---|---|---|
| 9/27/95 2300 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 9/26/95 0929 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 9/20/95 2326 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 9/13/95 2300 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 9/6/95 2319 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 10/25/95 2328 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 10/18/95 2329 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 10/16/95 1313 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 10/12/95 0005 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 10/4/95 2300 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 11/30/95 0050 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 11/29/95 1447 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 11/27/95 1208 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 11/24/95 1631 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 11/23/95 0021 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 11/22/95 1727 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 11/15/95 2319 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 11/8/95 2248 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 11/1/95 2340 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 12/6/95 2256 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 12/13/95 2355 hours (on line) | 239.4 KV | 4.438 KV (1.067 pu) |
| 12/17/95 1715 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 12/17/95 2051 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 12/18/95 1819 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 12/18/95 1853 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 12/19/95 0541 hours (on line) | 240.8 KV | 4.464 KV (1.073 pu) |
| 12/19/95 1303 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 12/20/95 0011 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 12/21/95 0352 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 12/21/95 2038 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 12/28/95 0003 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |

**Table 1 (continued)**

| Date, time (plant status) | 230 KV Offsite Source Voltage (From PPM 7.4.8.1.1.1.1) (note: E-TR-S has a minus 2.5% tap) | Voltage in KV and Per Unit on Generator Rated Voltage. (Determined by using transformer turns ratio to give secondary voltage at no load.) |
|---|---|---|
| 1/3/96 1921 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 1/8/96 2108 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 1/10/96 2214 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 1/15/96 1249 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 1/18/96 1304 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 1/17/96 2330 hours (on line) | 237 KV | 4.394 KV (1.056 pu) |
| 1/24/96 2208 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 1/31/96 2245 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 2/7/96 2258 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 2/7/96 0928 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 2/14/96 1430 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 2/20/96 0910 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 2/21/96 2147 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 2/28/96 2308 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 3/6/96 2325 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 3/13/96 1945 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 3/20/96 2322 hours (on line) | 240.6 KV | 4.460 KV (1.072 pu) |
| 3/27/96 2351 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 4/3/96 2012 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 4/11/96 0315 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 4/17/96 2149 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 4/24/96 2250 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 5/2/96 0022 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 5/6/96 1235 hours (off line) | 241 KV | 4.468 KV (1.074 pu) |
| 5/8/96 1937 hours (off line) | 239 KV | 4.431 KV (1.065 pu) |
| 5/15/96 1959 hours (off line) | 241.4 KV | 4.475 KV (1.076 pu) |
| 5/22/96 2034 hours (off line) | 240 KV | 4.449 KV (1.069 pu) |
| 5/30/96 0011 hours (off line) | 238.5 KV | 4.422 KV (1.063 pu) |

**Table 1 (continued)**

| Date, time (plant status) | 230 KV Offsite Source Voltage (From PPM 7.4.8.1.1.1.1) (note: E-TR-S has a minus 2.5% tap) | Voltage in KV and Per Unit on Generator Rated Voltage. (Determined by using transformer turns ratio to give secondary voltage at no load.) |
|---|---|---|
| 6/5/96 2024 hours (off line) | 238 KV | 4.412 KV (1.060 pu) |
| 6/13/96 2035 hours (off line) | 239 KV | 4.431 KV (1.065 pu) |
| 6/19/96 2034 hours (off line) | 237 KV | 4.394 KV (1.056 pu) |
| 6/26/96 0352 hours (off line) | 237 KV | 4.394 KV (1.056 pu) |
| 6/26/96 2152 hours (off line) | 236 KV | 4.375 KV (1.052 pu) |
| 7/3/96 2000 hours (on line) | 237 KV | 4.394 KV (1.056 pu) |
| 7/8/96 0947 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 7/10/96 2340 hours (on line) | 236.3 KV | 4.381 KV (1.053 pu) |
| 7/17/96 1844 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 7/24/96 2332 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 7/30/96 2207 hours (on line) | 236 KV | 4.375 KV (1.052 pu) |
| 7/31/96 2050 hours (on line) | 237 KV | 4.394 KV (1.056 pu) |
| 8/7/96 2330 hours (on line) | 238 KV | 4.412 KV (1.060 pu) |
| 8/8/96 1359 hours (on line) | 234.7 KV | 4.351 KV (1.046 pu) |
| 8/10/96 1744 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 8/15/96 0024 hours (on line) | 237 KV | 4.394 KV (1.056 pu) |
| 8/21/96 1907 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 8/28/96 1908 hours (on line) | 239 KV | 4.431 KV (1.065 pu) |
| 9/4/96 2129 hours (on line) | 242 KV | 4.486 KV (1.078 pu) |
| 9/11/96 1904 hours (on line) | 240 KV | 4.449 KV (1.069 pu) |
| 9/16/96 0858 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |
| 9/18/96 2234 hours (on line) | 241 KV | 4.468 KV (1.074 pu) |

Table 2

**Standby Generator Ratings**
(at full load)

| EDG No. | EDG-1 | EDG-2 | EDG-3 (HPCS) |
|---|---|---|---|
| KVA | 5812.5 | 5812.5 | 3560 |
| KW | 4650 | 4650 | 2850 |
| KVAR | 3487.5 | 3487.5 | 2136 |
| power factor | .8 | .8 | .8 |
| I phase (amps) | 806.7 | 806.7 | 494 |
| I exciter (amps) | 142.4 | 142.4 | 94 |

Figure 1 EDG-1 & EDG-2 1995 Test Load, Estimated Field Current (Isolated)

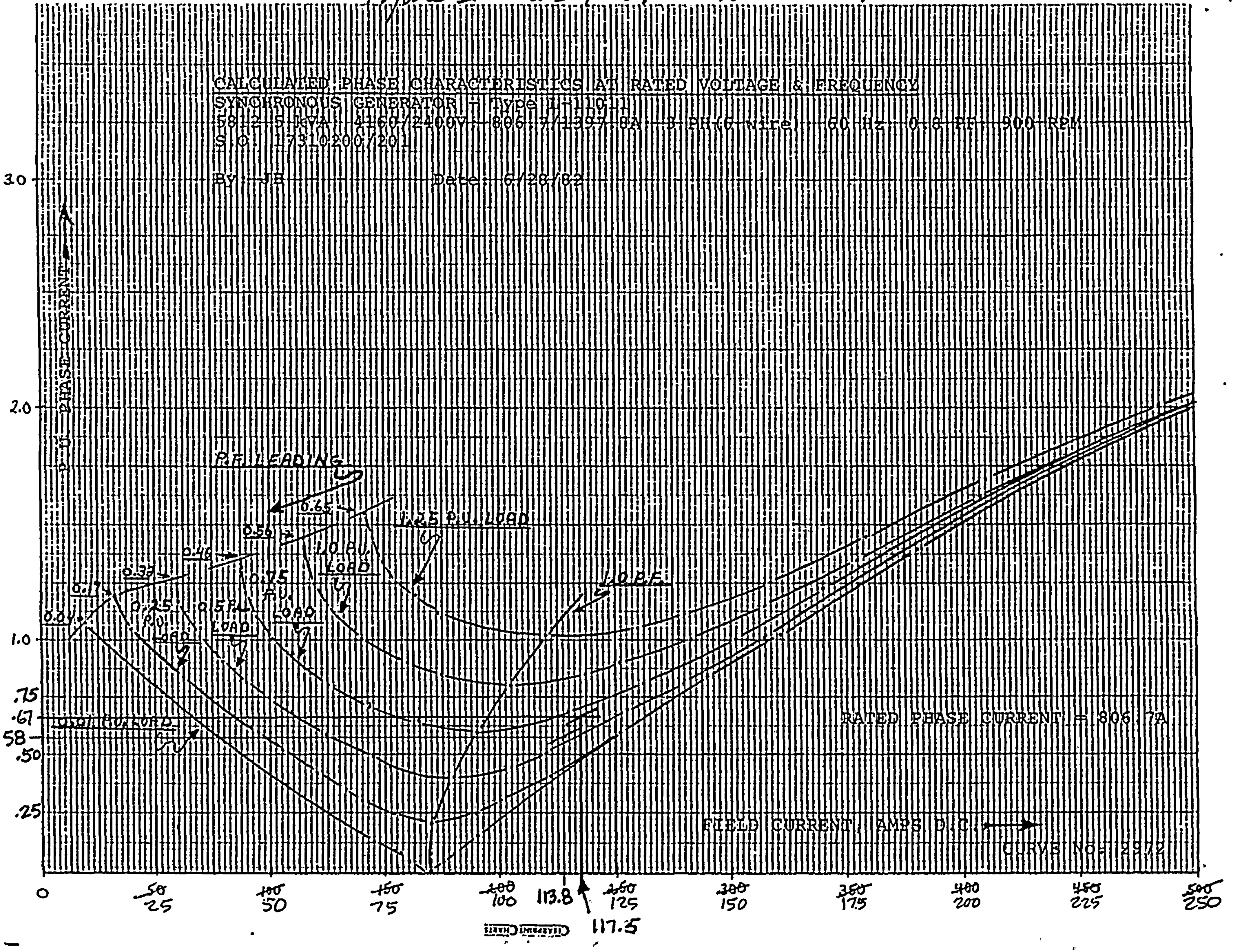
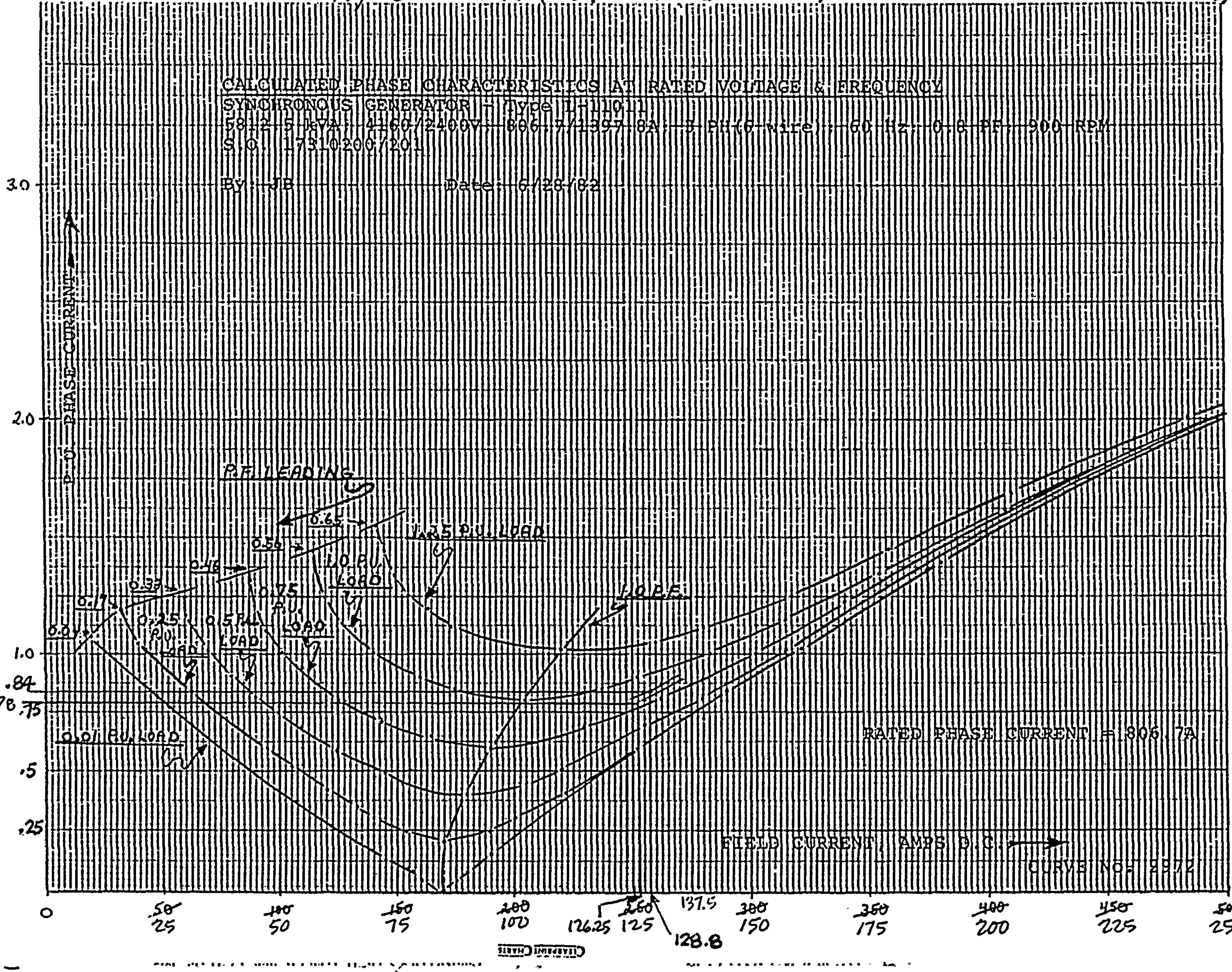


Figure 2 EDG-1 & EDG-2 Accident Load, Estimated Field Current (Isolated)



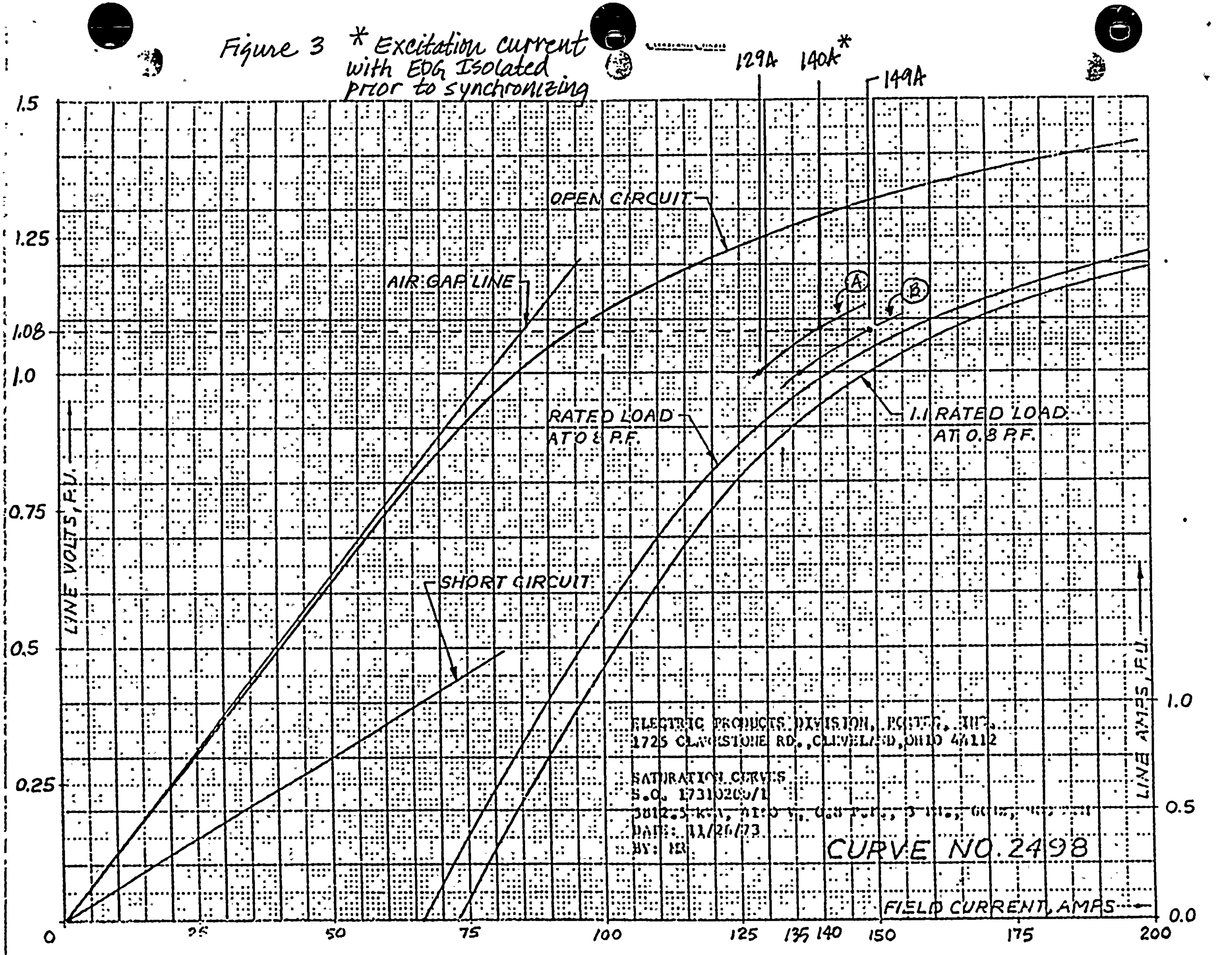


Figure 3 * Excitation current with EDG Isolated prior to synchronizing
129A
140A*
149A
OPEN CIRCUIT
AIR GAP LINE
A
B
RATED LOAD AT 0.8 P.F.
1.1 RATED LOAD AT 0.8 P.F.
SHORT CIRCUIT
LINE VOLTS, P.U.
LINE AMPS, P.U.
FIELD CURRENT, AMPS
1.5
1.25
1.08
1.0
0.75
0.5
0.25
0
25
50
75
100
125
135
140
150
175
200
1.0
0.5
0.0
SATURATION CURVES
DATE: 11/26/73
CURVE NO. 2498

# ATTACHMENT 3

## REVISION C

# VOLUME 2

50-397 WNP-2 WPPSS

ATTACHMENTS TO THE REQUEST FOR AMENDMENT TO
TECH SPECS (PART 2 of 2)

Rec'd w/ ltr dtd 12/12/96......9612260193

BASES (continued)

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS entered, the Division 3 AC sources provide no additional assurance of meeting the above criteria.

AC power requirements for MODES 4 and 5 and other conditions in which AC sources are required are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if a second circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features

(continued)

BASES

ACTIONS

A.2 (continued)

OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 9), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

The Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Problem Evaluation Request process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 10), 24 hours is a reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 9), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

BASES

ACTIONS

B.4 (continued)

Similar to Required Action B.2, the Completion Time of Required Action B.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 9) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division 3 (HPCS) is considered redundant to Divisions 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. Two offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

(continued)

BASES

ACTIONS

E.1 (continued)

electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 9), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with the other Division 1 or 2 DG remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent — an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, Division 3 systems (HPCS) could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 11). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 12), Regulatory Guide 1.108 (Ref. 13), and Regulatory Guide 1.137 (Ref. 14).

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. For Division 1 and 2 DGs, the minimum steady state output voltage depends upon whether or not the DG is tied to its respective 4.16 kV ESF bus. If the SR does not require the DG to be tied to its bus, then the minimum steady state output voltage is 3910 V, which is the minimum voltage necessary to meet the DG breaker closure interlock. If the SR requires the DG to be tied to its respective 4.16 kV ESF bus, then the minimum steady state output voltage is 3740 V. Studies have shown that with design basis maximum loading on the Class 1E distribution system, the Class 1E loads at all voltage levels (4160 V, 480 V, and 120 V) will have sufficient voltage at their terminals to meet or exceed their minimum voltage requirements when the voltage on the Class 1E 4.16 kV ESF bus is 3696 V or higher (Ref. 15). The specified value of 3740 V provides a conservative allowance for calculational uncertainties. For the Division 3 DG, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

minimum steady state output voltage is 3740 V. The basis for this value is the same as for the Division 1 and 2 DGs 3740 V value. The specified maximum steady state output voltage of 4400 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 Safety Guide 9 (Ref. 5) and Regulatory Guide 1.9 (Ref. 12).

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 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note 1 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

In order to reduce stress and wear on diesel engines, the manufacturer recommends that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2 to SR 3.8.1.2, which is only applicable when such procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 15 seconds. The 15 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 16). The 15 second start requirement may not be applicable to SR 3.8.1.2 (see Note 2 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 15 second start requirement of SR 3.8.1.7 applies. | C

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 12). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 10). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. | C

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. Since the generator is rated at a particular kVA at 0.8 power factor, the 0.8 value is the design rating of the machine. The 1.0 is an operational condition where the reactive power component is zero, which minimizes the reactive heating of the generator. Operating the generator

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

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 ESF 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. 12).

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 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%. For DGs 1 and 2, the required fuel oil level supports approximately 3.5 hours of operation at 110% of the continuous rated load. For DG-3, the required fuel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

oil level supports approximately 7 hours of operation at continuous rated load. The amount above the minimum 1 hour requirement helps to support the 7 day fuel oil supply.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the 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, 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. 14). 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 required fuel oil transfer pump 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 the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

The Frequency for this SR corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 17). | C

SR 3.8.1.8

Transfer of Division 1 and 2 4.16 kV ESF buses (SM-7 and SM-8) power supply from the startup offsite circuit to the backup offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the Division 1 and 2 shutdown loads. The 24 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 24 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 safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and 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 DG-1 and 2 is the | C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

1280 kW standby service water pump, and for DG-3 the 2380 kW HPCS pump. 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. 12), 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. For all the DGs, this corresponds to 66.75 Hz, which is the nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint. C

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 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 DG-1, ≤ 0.86 for DG-2, and ≤ 0.92 for DG-3. These power factors are representative of the actual single largest inductive load that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 580 kVAR for DG-1, 760 kVAR for DG-2, and 1015 kVAR for DG-3. However, if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to C C B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage 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 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 12), 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 $\leq 0.89$ for DG-1, $\leq 0.88$ for DG-2, and $\leq 0.91$ for DG-3. These power factors are representative of the actual design basis inductive loading that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

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 if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the reactive load may be reduced to maintain excitation current within the continuous rating. However, the excitation current shall be maintained ≥ 90% of the continuous rating of 142.4 amps for DG-1 and DG-2 and 100 amps for DG-3. This is to avoid conditions where the generator excitation system continuous rating limits can be exceeded or excessive transients can challenge equipment ratings due to network disturbances or spurious operation of breakers in the AC distribution system. B C

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 12), 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 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. C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The DG auto-start and energization of permanently connected loads times of 15 seconds for Division 1 and 2 and 18 seconds for Division 3 are derived from requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 16). The DG-3 18 second start time includes the Loss of Voltage—Time Delay Function specified in LCO 3.3.8.1. The Surveillance should be continued for a minimum of 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 permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these 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 and 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (15 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.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. |C

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. 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 the 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 and 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 this SR could cause perturbations to the electrical distribution systems that could challenge

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 12), 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, generator differential current, and incomplete starting sequence) 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. | C

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 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 12), 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 duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The | C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

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 ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3. These power factors are representative of the actual design basis inductive loading that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. C C B

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 transients of excitation current or power factor 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. Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage does not permit the C B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

power factor limit to be met when the DG is tied to the grid. When this occurs, the reactive load may be reduced to maintain excitation current within the continuous rating. However, the excitation current shall be maintained ≥ 90% of the continuous rating of 142.4 amps for DG-1 and DG-2 and 100 amps for DG-3. This is to avoid conditions where the generator excitation system continuous rating limits can be exceeded or excessive transients can challenge equipment ratings due to network disturbances or spurious operation of breakers in the AC distribution system.

SR 3.8.1.15

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 15 seconds. The 15 second time is derived from the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 16).

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 1 hour at 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 3.8.1.16

Consistent with Regulatory Guide 1.9 (Ref. 12), 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

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 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 3.8.1.17

Consistent with Regulatory Guide 1.9 (Ref. 12), 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. 18), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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 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 3.8.1.18

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 tolerance ensures that a sufficient time interval 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. Since only DG-1 and DG-2 have more than one load block, this SR is only applicable to these DGs.

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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. Since the DG-3 Loss of Voltage—Time Delay Function is bypassed during an ECCS initiation signal, a 15 second DG-3 start time applies, consistent with the DBA LOCA analysis (Ref. 16). In lieu of actual demonstration of connection and loading of 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 an expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove 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 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.14.

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. FSAR, Figure 8.3-23.
4. FSAR, Tables 8.3-1, 8.3-2, and 8.3-3.
5. Safety Guide 9, Revision 0, March 1971.
6. FSAR, Chapter 6.
7. FSAR, Chapters 15 and 15.F.
8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
9. Regulatory Guide 1.93, Revision 0, December 1974.
10. Generic Letter 84-15, July 2, 1984.
11. 10 CFR 50, Appendix A, GDC 18.
12. Regulatory Guide 1.9, July 1993.
13. Regulatory Guide 1.108, Revision 1, August 1977.
14. Regulatory Guide 1.137, Revision 1, October 1979.
15. Supply System Calculations Nos. E/I-02-87-07 and E/I-02-90-01.

(continued)

BASES

REFERENCES (continued)

16. FSAR, Section 15.F.6.
17. ASME, Boiler and Pressure Vessel Code, Section XI.
18. IEEE Standard 308-1974.

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.2 AC Sources – Shutdown

BASES

| | |
|---|---|
| BACKGROUND | A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources – Operating." |

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shutdown the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs), which are analyzed in MODES 1, 2, and 3, have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded.

During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 1).

LCO

One offsite circuit supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems — Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with

(continued)

BASES

LCO (continued)

a Division 1 or Division 2 Distribution System Engineered Safety Feature (ESF) bus required OPERABLE by LCO 3.8.8, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) is required to be OPERABLE, an OPERABLE Division 3 DG ensures an additional source of power for the HPCS. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel draindown).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective ESF bus(es), and accepting required loads during an accident. Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant. The qualified offsite circuit includes the circuit path and disconnect to the respective transformer, the circuit path and breakers to the respective non-Class 1E 4.16 kV switchgear, SM-1, SM-2, and SM-3 (for the TR-S offsite circuit only), and the circuit path and breakers to the respective Class 1E switchgear (SM-4, SM-7, and SM-8) required by LCO 3.8.8.

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 15 seconds for Divisions 1 and 2, and 18 seconds for Division 3. The DG-3 18 second start time includes the Loss of Voltage — Time Delay Function specified in LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation." Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO (continued)

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. The necessary portions of the Standby Service Water and HPCS Service Water systems are also required to provide appropriate cooling to each required DG.

It is acceptable for divisions to be cross-tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions. No fast transfer capability is required for offsite circuits to be considered OPERABLE.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES

ACTIONS (continued)

A.1

An offsite circuit is considered inoperable if it is not available to one required ESF division. If two or more ESF 4.16 kV buses are required per LCO 3.8.8, division(s) with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable that are not powered from offsite power, appropriate restrictions can be implemented in accordance with the required feature(s) LCOs' ACTIONS. Required features remaining powered from a qualified offsite power circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

(continued)

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

---

BACKGROUND

Each diesel generator (DG) is provided with a storage tank which, in combination with the associated day tank, has a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources. Additional onsite storage is also provided by the auxiliary boiler fuel storage tank. The quality of the fuel in this tank is maintained in accordance with the requirements for the fuel stored in the DG storage and day tanks. However, no credit for accident mitigation is allowed for the quantity of the fuel stored in the auxiliary boiler fuel storage tank.

Fuel oil is transferred from each storage tank to its respective day tank by a transfer pump associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated locally and is provided with high and low level switches which actuate alarm annunciators in the main control room. The transfer pump on the filter polishing skid is used to move fuel oil from the auxiliary boiler fuel storage tank to each of the DG storage tanks. The auxiliary boiler and filter polishing systems and associated components are not required to conform to all of the guidelines in Regulatory Guide 1.137 1C
(Ref. 2), because failure of a component or rupture of the piping would not result in the loss of a DG.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity or absolute specific gravity), and impurity level.

(continued)

BASES

BACKGROUND (continued)

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Division 1 and 2 DGs each have an air start subsystem that includes two air start receivers (each receiver has four air tanks), each with adequate capacity for five successive starts without recharging the air start receiver. The Division 3 DG has an air start subsystem that includes two air start receivers, each with adequate capacity for three successive starts without recharging the air receivers.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in FSAR, Chapter 6 (Ref. 4) and Chapters 15 and 15.F (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement (Ref. 6).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to

(continued)

BASES

LCO (continued)

maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

The starting air system is required to have a minimum capacity for five successive Division 1 and 2 DG starts and three successive Division 3 DG starts without recharging the air start receivers. Only one air start receiver (and associated air start header) per DG is required, since each air start receiver has the required capacity.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air subsystems support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

<u>A.1</u>

With fuel oil level < 55,500 gallons in a Division 1 or 2 DG storage tank, or < 33,000 gallons in the Division 3 DG storage tank, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

(continued)

BASES

ACTIONS

A.1 (continued)

a. Full load operation required after an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < 330 gallons for a Division 1 or 2 DG, or < 165 gallons for the Division 3 DG, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory

(continued)

BASES

ACTIONS

C.1 (continued)

analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With required starting air receiver pressure < 230 psig for a Division 1 or 2 DG, or < 223 psig for the Division 3 DG, sufficient capacity for five successive DG starts for a Division 1 or 2 DG, and three successive DG starts for the Division 3 DG does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required

(continued)

BASES

ACTIONS

E.1 (continued)

pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification, in conjunction with SR 3.8.1.4, that there is an adequate inventory of fuel oil to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory (combined inventory in the DG lube oil sump(s) and in the warehouse) is available to support at least 7 days of full load operation for each DG. The 330 gallon requirement for Divisions 1 and 2 DGs and the 165 gallon requirement for Division 3 DG are based on the DG manufacturer's consumption values for the run time of the DG. Normally, sufficient volume is maintained in the DG lube oil sump(s) to meet the 7 day requirement (adequate inventory is maintained when the DG lube oil sump(s) are > 9 inches above the lower mark on

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

the dipstick(s) with the DG secured and the lube oil circulating pump off). However, implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sump(s) do not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level (the lower mark on the dipstick(s)).

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding results) of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-88 (Ref. 7); | C

b. Verify in accordance with the tests specified in ASTM D975-94 (Ref. 7) that: (1) the sample has an API gravity of within 0.3° at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 39°; (2) a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification; and (3) a flash point of ≥ 125°F; and | C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

c. Verify that the new fuel oil has a water and sediment content of ≤ 0.05% volume when tested in accordance with ASTM D1796-83 (Ref. 7) or a clear and bright appearance with proper color when tested in accordance with ASTM D4176-93 (Ref. 7). 1C 1C

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-94 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-94 (Ref. 7). These additional analyses are required by Specification 5.5.9, Diesel Fuel Oil Testing Program, to be performed within 31 days following sampling and addition. This 31 day requirement is intended to assure that: 1C

a. The new fuel oil sample taken is no more than 31 days old at the time of adding the new fuel oil to the DG storage tank; and

b. The results of the new fuel oil sample are obtained within 31 days after addition of the new fuel oil to the DG storage tank.

The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

Particulate concentrations should be determined in accordance with ASTM D2276-93, Method A (Ref. 7). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate concentration is unlikely to change between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles for Division 1 and 2 DGs and three engine start cycles for the Division 3 DG without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the five or three starts, as applicable, can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the storage tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, rain water,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is established by Regulatory Guide 1.137 (Ref. 2) and is 92 days since the ground water table is lower than the bottom of the fuel oil storage tanks. 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 the Surveillance.

REFERENCES

1. FSAR, Section 9.5.4.
2. Regulatory Guide 1.137, Revision 1, October 1979.
3. ANSI N195, Appendix B, 1976.
4. FSAR, Chapter 6.
5. FSAR, Chapters 15 and 15.F.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. ASTM Standards: D4057-88; D975-94; D4176-93; D1796-83; D2276-93.

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.4 DC Sources — Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of three independent Class 1E DC electrical power subsystems, Divisions 1, 2, and 3. The 250 VDC electrical power system consists of one Class 1E DC electrical power subsystem, Division 1. Each subsystem consists of a battery, associated battery charger, and all the associated control equipment and interconnecting cabling.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the Engineered Safety Feature (ESF) batteries.

The Division 1 safety related DC power source consists of one 125 V and one 250 V battery bank and associated full capacity battery chargers (one per battery bank). The 125 V battery provides the control power for its associated Class 1E AC power load group, 4.16 kV switchgear and 480 V load centers. Also, the 125 V battery provides DC power to the emergency lighting system, diesel generator (DG) auxiliaries and the DC control power for DG-1. The 250 V battery supplies power to various reactor core isolation cooling system, residual heat removal and reactor water cleanup system valves. It also supplies power on an uninterruptible basis to plant controls, instrumentation, computer and communication equipment through a solid state inverter and the main and feedwater turbine auxiliary oil pumps; however, these loads are not TS related loads.

(continued)

BASES

BACKGROUND (continued)

The Division 2 safety related DC power source consists of a 125 V battery bank and associated full capacity charger. This DC power source provides the control power for its associated Class 1E AC power load group, 4.16 kV switchgear and 480 V load centers. Also, this DC power source provides DC power to the emergency lighting system, DG auxiliaries and the DC control power for DG-2.

The Division 3 125 VDC power system provides power for HPCS DG field flashing control logic and control and switching function of 4.16 kV Division 3 breakers. It also provides motive and control power for the HPCS System logic, HPCS DG control and protection, and all Division 3 related control.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution Systems — Operating," and LCO 3.8.8, "Distribution Systems — Shutdown."

Each Division 1, 2, and 3 battery has adequate storage capacity to carry the required load continuously for at least 2 hours as discussed in the FSAR, Section 8.3.2 (Ref. 4).

The Division 1 125 V and 250 V, and Division 2 125 VDC electrical power subsystem components are located in the radwaste/control building, a Seismic Category I structure. The Divisions 1 and 2 DC buses and the associated equipment are located such that redundant counterparts are physically separated from each other. The Division 3 DC electrical power subsystem components are located in the diesel generator building, also a Seismic Category I structure. There are no connections between DC systems of different divisions, and there is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

The 125 V batteries are sized to produce required capacity at 80% of nameplate rating. The 250 V battery is sized to produce the required capacity at 83.4% of the nameplate rating. These values correspond to warranted capacity at end-of-life cycles and the 100% design demand for each of the batteries. The voltage design limit is 1.81 volts per cell (Refs. 5 and 6).

(continued)

BASES

| | |
|---|---|
| BACKGROUND (continued) | Each DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads (Ref. 4). |
| APPLICABLE SAFETY ANALYSES | The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 7) and Chapters 15 and 15.F (Ref. 8), assume that ESF systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.<br><br>The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:<br><br>a. An assumed loss of all offsite AC power or of all onsite AC power; and<br><br>b. A worst case single failure.<br><br>The DC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 9). |
| LCO | The DC electrical power subsystems, each subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the divisions, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). |

(continued)

BASES (continued)

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 4 and 5 and other conditions in which the DC electrical power sources are required are addressed in LCO 3.8.5, "DC Sources—Shutdown."

ACTIONS

A.1

Condition A represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of 125 VDC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system division.

If one of the required Division 1 or 2 125 VDC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger, or inoperable battery charger and associated inoperable battery), the remaining 125 VDC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary 125 VDC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 10) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

(continued)

BASES

ACTIONS (continued)

B.1

With the Division 3 DC electrical power subsystem inoperable, the HPCS System may be incapable of performing its intended function and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS—Operating."

C.1

With the Division 1 250 VDC electrical power subsystem inoperable, the RCIC and other associated supported features may be incapable of performing their intended functions and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions for the associated supported features.

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time specified in Regulatory Guide 1.93 (Ref. 10).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is conservative when compared with the manufacturers recommendations and IEEE-450 (Ref. 11).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, and inter-tier connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

For inter-cell connectors, the limits are ≤ 24.4 E-6 ohms for the Division 1 and 2 batteries and ≤ 169 E-6 ohms for the Division 3 battery. For inter-tier and inter-rack connectors, the limits are ≤ 20% above the resistance as measured during installation.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 12 month Frequency of this SR is consistent with IEEE-450 (Ref. 11), which recommends detailed visual inspection of cell condition on a yearly basis. B

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, and inter-tier connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

For inter-cell connectors, the limits are $\leq$ 24.4 E-6 ohms for the Division 1 and 2 batteries and $\leq$ 169 E-6 ohms for the Division 3 battery. For inter-tier and inter-rack connectors, the limits are $\leq$ 20% above the resistance as measured during installation.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 11), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis. B

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 12), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. The charger shall be loaded, to a minimum, at three separate and sequential load ratings, 50%, 75%, and 100%, for $\geq$ 30 minutes at each load rating. The 100% load rating for the Divisions 1 and 2 125 V battery chargers is 200 amps, for the Division 3 125 V battery charger is 50 amps, and for the Division 1 250 V battery charger is 400 amps. C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is acceptable, given unit conditions required to perform the test and the other requirements existing to ensure adequate battery performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test once per 60 months. This substitution is acceptable because a modified performance discharge test represents a more severe test of battery capacity than SR 3.8.4.7. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

A battery modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance discharge test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed at a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery performance discharge test for the duration of time equal to that of the battery performance discharge test.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a performance discharge test.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 11) and IEEE-485 (Ref. 13) for the 125 V batteries. These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating, since IEEE-485 (Ref. 13) recommends using an aging factor of 125% in the battery sizing calculations. The acceptance criteria for this Surveillance for the 250 V battery is consistent with Reference 5. This reference recommended that the battery be replaced if its capacity is below 83.4% of the manufacturer's rating in lieu of References 11 and 13 recommendation of 80%, since the battery sizing calculation in Reference 5 uses an aging

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

factor of 120%. A capacity of 80% for the 125 V battery and 83.4% for the 250 V battery shows that the battery is getting old and capacity will decrease more rapidly, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 18 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450, 1975 (Ref. 14), when the battery capacity drops by more than 10% relative to its average on previous performance tests or when it is below 90% of the manufacturer's rating. For the 250 V battery, degradation is indicated when it is below 93.4% of the manufacturer's rating in lieu of 90%. This ensures the accelerated testing schedule is implemented when the 250 V battery capacity decreases to 10% above the capacity at which the battery must be replaced (consistent with the 125 V batteries), since the 250 V battery must be replaced when the capacity falls to 83.4%. The 12 month and 60 month Frequencies are consistent with the recommendations in IEEE-450 (Ref. 11). The 24 month Frequency is derived from the recommendations in IEEE-450 (Ref. 11).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, Revision 0, March 10, 1971.
3. IEEE Standard 308, 1974.
4. FSAR, Section 8.3.2.

(continued)

BASES

REFERENCES (continued)

5. WNP-2 Calculation 2.05.01, Rev. 8, February 1990.

6. WNP-2 Calculation E/I 02-85-02, Rev. 1, April 1989.

7. FSAR, Chapter 6.

8. FSAR, Chapters 15 and 15.F.

9. Final Policy Statement on Technical Specifications Improvements, July 12, 1993 (58 FR 39132).

10. Regulatory Guide 1.93, December 1974.

11. IEEE Standard 450, 1987.

12. Regulatory Guide 1.32, February 1977.

13. IEEE Standard 485, 1983.

14. IEEE Standard 450, 1975.

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.5 DC Sources — Shutdown

BASES

| | |
|---|---|
| BACKGROUND | A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources — Operating." |
| APPLICABLE SAFETY ANALYSES | The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapters 15 and 15.F (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation and during movement of irradiated fuel assemblies in the secondary containment.<br><br>The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.<br><br>The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:<br><br>a. The facility can be maintained in the shutdown or refueling condition for extended periods;<br><br>b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and<br><br>c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.<br><br>The DC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 3). |
| LCO | The DC electrical power subsystems, each consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the division, are required to be |

(continued)

BASES

| | |
|---|---|
| LCO (continued) | OPERABLE to support required Distribution System divisions required OPERABLE by LCO 3.8.8, "Distribution Systems – Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown). |

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES

ACTIONS (continued)

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If more than one DC distribution subsystem is required according to LCO 3.8.8, the DC electrical power subsystems remaining OPERABLE with one or more DC electrical power subsystems inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with associated DC electrical power subsystem(s) inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. However, in many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

(continued)

BASES

| | |
|---|---|
| SURVEILLANCE REQUIREMENTS | SR 3.8.5.1 (continued)<br><br>This SR is modified by a Note. The reason for the Note is to preclude requiring OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required. |
| REFERENCES | 1. FSAR, Chapter 6.<br><br>2. FSAR, Chapters 15 and 15.F.<br><br>3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). |

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.6 Battery Cell Parameters

BASES

| | |
|---|---|
| BACKGROUND | This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources — Operating," and LCO 3.8.5, "DC Sources — Shutdown." |
| APPLICABLE SAFETY ANALYSES | The initial conditions of Design Basis Accident (DBA) and transient analyses in FSAR, Chapter 6 (Ref. 1) and Chapters 15 and 15.F (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.<br><br>The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as discussed in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."<br><br>Since battery cell parameters support the operation of the DC power sources, they satisfy Criterion 3 of the NRC Policy Statement (Ref. 3). |
| LCO | Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with limits not met. |

(continued)

BASES (continued)

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, these cell parameters are only required when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell(s) electrolyte level and float voltage are required to be verified to meet Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell(s). One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

(continued)

BASES

ACTIONS

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as any Required Action of Condition A and associated Completion Time not met or average electrolyte temperature of representative cells ≤ 60°F, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

The SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 4), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 4). In addition, within 24 hours of a battery discharge < 110 V for a 125 V battery and < 220 V for the 250 V battery, or a battery overcharge > 150 V for a 125 V battery and > 300 V for the 250 V battery, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to < 110 V or < 220 V, as applicable, do not constitute a battery discharge provided the battery terminal voltage and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.2 (continued)

float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 4), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is > 60°F is consistent with a recommendation of IEEE-450 (Ref. 4), which states that the temperature of electrolytes in representative cells (i.e., one-sixth of the cells) should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer's recommendations and battery sizing calculations.

Table 3.8.6-1

This Table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 4), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be temporarily above the specified maximum level during and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

following an equalizing charge (i.e., for up to 3 days following the completion of an equalize charge), provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 4) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on manufacturer's recommendations, and on the recommendation of IEEE-450 (Ref. 4), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.200 (0.015 below the manufacturer's fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 4), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer's fully charged,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for float voltage is based on IEEE-450, Appendix C (Ref. 4), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement. 1C

The Category C limit of average specific gravity (≥ 1.195), is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote b requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of acceptable overall battery condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charging current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 4). Footnote c allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as an equalizing charge that does not follow a deep discharge), specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapters 15 and 15.F.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
4. IEEE Standard 450, 1987.

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.7 Distribution Systems—Operating

BASES

**BACKGROUND**

The onsite Class 1E AC and DC electrical power distribution system is divided by division into three independent AC and DC electrical power distribution subsystems.

The primary AC Distribution System consists of three 4.16 kV Engineered Safety Feature (ESF) buses that are supplied from the transmission system by two physically independent circuits. Each 4.16 kV ESF bus also has a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally (when the main generator is on line) connected to the auxiliary transformer TR-N1, or a qualified offsite source. If the main generator and all qualified offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources—Operating," and the Bases for LCO 3.8.4, "DC Sources—Operating."

The secondary plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers. Control power for the 480 V breakers is from the Class 1E batteries.

There are three independent 125 VDC electrical power distribution subsystems. The list of required distribution buses is located in Table B 3.8.7-1.

**APPLICABLE SAFETY ANALYSES**

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapters 15 and 15.F (Ref. 2), assume ESF systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

(continued)

BASES

**APPLICABLE SAFETY ANALYSES (continued)**

The OPERABILITY of the AC and DC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite or onsite AC electrical power; and

b. A worst case single failure.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

**LCO**

The required AC and DC power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1, 2, and 3 AC and DC electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Division 1, 2, and 3 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger.

(continued)

BASES

LCO (continued)

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.7-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other buses, such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., loss of a 4.16 kV ESF, which results in de-energization of all buses powered from the 4.16 kV ESF bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV ESF bus).

In addition, tie breakers between redundant safety related AC power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystems) are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

(continued)

BASES (continued)

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and DC electrical power distribution subsystems are required are covered in LCO 3.8.8, "Distribution Systems — Shutdown." | C

ACTIONS

A.1

With one or more Division 1 or 2 required AC buses, load centers, motor control centers, or distribution panels, in one division inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

(continued)

BASES

ACTIONS

A.1 (continued)

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 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 restore the AC electrical power distribution system. At this time, a DC bus could again become inoperable, and the AC electrical power distribution system could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

B.1

With Division 1 or 2 125 VDC buses in one division inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it

(continued)

BASES

ACTIONS

B.1 (continued)

in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystem must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition B represents one division without adequate 125 VDC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that could be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, that would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 4).

(continued)

BASES

ACTIONS

B.1 (continued)

The second Completion Time for Required Action B.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 B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC electrical power distribution system. At this time, an AC bus could again become inoperable, and DC electrical power distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

C.1 and C.2

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, 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

With the Division 1 250 VDC electrical power distribution subsystem inoperable, the RCIC System and other associated supported features are not capable of performing their intended functions. Immediately declaring the RCIC System and other associated supported features inoperable allows the ACTIONS of the associated LCOs to apply appropriate limitations on continued reactor operation.

(continued)

BASES

ACTIONS (continued)

E.1

With the Division 3 electrical power distribution system inoperable, the Division 3 powered systems are not capable of performing their intended functions. Immediately declaring the High Pressure Core Spray System inoperable allows the ACTIONS of LCO 3.5.1, "ECCS—Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one Condition is entered and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms or by verifying a load powered from the bus is operating. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapters 15 and 15.F.
3. Final Policy Statement on Technical Specification Improvements, July 22, 1993 (58 FR 39132).
4. Regulatory Guide 1.93, December 1974.

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

| TYPE | VOLTAGE | DIVISION 1[a] | DIVISION 2[a] | DIVISION 3[a] |
|---|---|---|---|---|
| AC buses | 4160 V | SM-7 | SM-8 | SM-4 |
| | 480 V | SL-71 and SL-73<br>Motor Control Centers 7A, 7A-A, 7B, 7B-A, 7B-B, and 7F<br>Power Panel PP-7A-B | SL-81 and SL-83<br>Motor Control Centers 8A, 8A-A, 8B, 8B-A, 8B-B, and 8F<br>Power Panel PP-8A-B | 3 Phase Engine and Generator Auxiliary Loads Power Panel<br>Motor Control Center 4A |
| | 120/240 V | 1 Phase Power Panels PP-7A-A, PP-7A-F, PP-7A-E, and PP-7A | 1 Phase Power Panels PP-8A-A PP-8A-F, PP-8A-E, and PP-8A | 1 Phase Power Panel PP-4A |
| | 120/208 V | 3 Phase Power Panels PP-7A-G and PP-7A-A-A | 3 Phase Power Panels PP-8A-G and PP-8A-A-A | |
| DC buses | 250V | Main Distribution Panel S2-1<br>Motor Control Center MC-S2-1A, Part A and Part B | | |
| | 125 V | S1-1<br>Motor Control Center MC-S1-1D<br>Instrument and Control NSSS Board Distribution Panel DP-S1-1A<br>Remote Shutdown Distribution Panel DP-S1-1D<br>Diesel Generator 1 Distribution Panel DP-S1-1E<br>Critical Switchgear Distribution Panel DP-S1-1F | S1-2<br>Motor Control Center MC-S1-2D<br>Instrument and Control NSSS Board Distribution Panel DP-S1-2A<br>Critical Switchgear and Remote Shutdown Distribution Panel DP-S1-2D<br>Diesel Generator 2 Distribution Panel DP-S1-2E | HPCS Distribution Panel |

(a) Each division of the AC and DC electrical power distribution system is a subsystem.

# B 3.8 ELECTRICAL POWER SYSTEMS

## B 3.8.8 Distribution Systems — Shutdown

BASES

| | |
|---|---|
| BACKGROUND | A description of the AC and DC electrical power distribution systems is provided in the Bases for LCO 3.8.7, "Distribution Systems — Operating." |

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapters 15 and 15.F (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications' required systems, equipment, and components—both specifically addressed by their own LCOs, and implicitly required by the definition of OPERABILITY.

In addition, it is acceptable for required buses to be cross-tied during shutdown conditions, permitting a single source to supply multiple redundant buses, provided the source is capable of maintaining proper frequency (if required) and voltage.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal-shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the correct breaker alignment. The correct breaker alignment ensures power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms or by verifying a load powered from the bus is operating. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapters 15 and 15.F.

3. Final Policy Statement on Technical Specification Improvements, July 22, 1993 (58 FR 39132).

# B 3.10 SPECIAL OPERATIONS

## B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

---

**BACKGROUND**

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3).

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation, decay heat, and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases for a given pressure. Periodic updates to the RCS P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel.

---

**APPLICABLE SAFETY ANALYSES**

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 200°F, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the hydrostatic or leak tests are performed nearly water solid (except for an air bubble for pressure control), at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.8, "Reactor Coolant System (RCS) Specific Activity," are minimized. In

(continued)

BASES

| | |
|---|---|
| LCO (continued) | If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purposes of performing either an inservice leak or hydrostatic test. |
| | This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation. |
| APPLICABILITY | The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 200°F. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO. |
| ACTIONS | A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO. |

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

C.1

When the HPCS is required to be OPERABLE, and the Division 3 DG is inoperable, the required diversity of AC power sources to the HPCS is not available. Since these sources only affect the HPCS, the HPCS is declared inoperable and the Required Actions of LCO 3.5.2, "Emergency Core Cooling System – Shutdown" entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.8 be taken. If only the Division 3 DG is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the DG to OPERABLE. This is reasonable considering HPCS will still perform its function, absent an additional single failure. 1C

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude de-energizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE.

REFERENCES

1. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

# VOLUME 7

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.4.2 - JET PUMPS

1 C

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 to the Surveillance would allow two methods to perform the Surveillance as identified in GE SIL-380. However, the jet pumps are not considered as initiators of any previously evaluated accident. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Additionally, the proposed Surveillance will continue to provide adequate confirmation of the OPERABILITY of the jet pumps. Therefore, the proposed change will not increase 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 proposed Surveillance will continue to provide the necessary assurance of OPERABILITY of the jet pumps.

## L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change does not result in any hardware or operating procedure changes. The requirement to place the reactor mode switch in Shutdown in the event of a stuck open SRV is not assumed in the initiation of any analyzed event. The requirement of Action b of Specification 3/4.4.2 was provided to ensure that, in the event of a stuck open safety/relief valve which could not be closed in a timely manner, the reactor mode switch would be placed in the Shutdown position in anticipation of exceeding a suppression pool average temperature of 110°F. However, Required Action D.1 of proposed Specification 3.6.2.1 will still require that the reactor mode switch be immediately placed in Shutdown if the suppression pool average temperature is ≥ 110°F. As such, the Required Actions of proposed Specification 3.6.2.1 are adequate to ensure that the reactor mode switch will immediately be placed in the Shutdown position if the suppression pool average temperature exceeds 110°F. As a result, accident consequences are unaffected by the deletion of the requirement to place the reactor mode switch in the Shutdown position if a stuck open safety/relief valve is unable to be closed within 2 minutes. Therefore, this change will not involve a significant increase in the probability or 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   This change deletes the requirement to place the reactor mode switch in the Shutdown position if a stuck open safety/relief valve is unable to be closed within 2 minutes. This requirement of Action b of Specification 3/4.4.2 was provided to ensure that, in the event of a stuck open safety/relief valve which could not be closed in a timely manner, the reactor mode switch would be placed in the Shutdown position in anticipation of exceeding a suppression pool average temperature of 110°F. However, Required Action D.1 of proposed Specification 3.6.2.1 will still require that the reactor mode switch be immediately placed in Shutdown if the suppression pool average temperature is ≥ 110°F. As such, the Required Actions of proposed Specification 3.6.2.1 are adequate to ensure that the reactor mode switch will immediately be

L.1 CHANGE

3. (continued)

placed in the Shutdown position if the suppression pool average temperature exceeds 110°F. In addition, Emergency Operating Procedures address the appropriate actions to take in response to a stuck open safety/relief valve. As a result, continued assurance is provided that plant operation will be maintained with safety analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

 1C

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change does not result in any hardware or operating procedure changes. The requirement to place the reactor mode switch in Shutdown in the event of a stuck open SRV is not assumed in the initiation of any analyzed event. The requirement of Action b of Specification 3/4.4.2 was provided to ensure that, in the event of a stuck open safety/relief valve which could not be closed in a timely manner, the reactor mode switch would be placed in the Shutdown position in anticipation of exceeding a suppression pool average temperature of 110°F. However, Required Action D.1 of proposed Specification 3.6.2.1 will still require that the reactor mode switch be immediately placed in Shutdown if the suppression pool average temperature is ≥ 110°F. As such, the Required Actions of proposed Specification 3.6.2.1 are adequate to ensure that the reactor mode switch will immediately be placed in the Shutdown position if the suppression pool average temperature exceeds 110°F. As a result, accident consequences are unaffected by the deletion of the requirement to place the reactor mode switch in the Shutdown position if a stuck open safety/relief valve is unable to be closed within 2 minutes. Therefore, this change will not involve a significant increase in the probability or 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   This change deletes the requirement to place the reactor mode switch in the Shutdown position if a stuck open safety/relief valve is unable to be closed within 2 minutes. This requirement of Action b of Specification 3/4.4.2 was provided to ensure that, in the event of a stuck open safety/relief valve which could not be closed in a timely manner, the reactor mode switch would be placed in the Shutdown position in anticipation of exceeding a suppression pool average temperature of 110°F. However, Required Action D.1 of proposed Specification 3.6.2.1 will still require that the reactor mode switch be immediately placed in Shutdown if the suppression pool average temperature is ≥ 110°F. As such, the Required Actions of proposed Specification 3.6.2.1 are adequate to ensure that the reactor mode switch will immediately be

L.1 CHANGE

3. (continued)

placed in the Shutdown position if the suppression pool average temperature exceeds 110°F. In addition, Emergency Operating Procedures address the appropriate actions to take in response to a stuck open safety/relief valve. As a result, continued assurance is provided that plant operation will be maintained with safety analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

lC

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 would revise the Applicability of the unidentified leakage rate increase to include only MODE 1, instead of the current MODES 1, 2, and 3. The limit is intended to be applied to changes from normal steady state operation leakage rates. These are typically established at operating pressure and temperatures consistent with MODE 1. In this manner, a change that indicates a potential problem can be investigated prior to a catastrophic pipe rupture. However, a change during a heatup or startup that does not exceed an unidentified leakage of 5 gpm, in most cases, does not indicate a potential problem that could result in a catastrophic pipe rupture. The overall unidentified LEAKAGE limit of 5 gpm remains unchanged and will ensure changes that exceed this limit will not go unrecognized in MODES 2 and 3. Therefore the probability and consequences of a previously analyzed accident are not significantly increased.

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 proposed change does not modify the total unidentified LEAKAGE limit, and this limit is well below the leakage rate expected just prior to the onset of rapid crack propagation.

## L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change does not result in any hardware or operating procedure changes. The reactor vessel head flange leak detection system is not assumed in the initiation of any analyzed event. The reactor vessel head flange leak detection system does not necessarily relate directly to the LEAKAGE requirements. In addition, the current Technical Specifications do not specify this indication to be OPERABLE in the leakage detection instrumentation Specification (current LCO 3.4.3.1 and proposed ITS LCO 3.4.7), thus it is not needed to support the Operational LEAKAGE Specification. The requirement to demonstrate LEAKAGE is within limits is still maintained in SR 3.4.5.1. As a result, accident consequences are unaffected by the deletion of the reactor vessel head flange leak detection system requirements. Therefore, this change will not involve a significant increase in the probability or 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   The proposed deletion of the reactor vessel head flange leak detection system requirements does not impact any margin of safety. The reactor vessel head flange leak detection system does not necessarily relate directly to the LEAKAGE requirements. In addition, the current Technical Specifications do not specify this indication to be OPERABLE in the leakage detection instrumentation Specification (current LCO 3.4.3.1 and proposed ITS LCO 3.4.7), thus it is not needed to support the Operational LEAKAGE Specification. In addition, the requirement to demonstrate LEAKAGE is within limits is still maintained in SR 3.4.5.1. As a result, an explicit requirement to maintain the reactor vessel head flange leak detection system OPERABLE as a means of identifying and quantifying leakage from the reactor vessel head flange is not required. Therefore, this change does not involve a significant reduction in a margin of safety.

1C

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change does not result in any hardware or operating procedure changes. The PIV leakage limits are not assumed to be an initiator of any analyzed event. The leakage limits provide assurance of valve integrity thereby reducing the probability of gross PIV failure and thereby eliminating potential consequences. The change to the limits acknowledges that smaller valves should not be allowed to leak as much as larger valves. The change provides assurance the PIVs will not be subject to gross failure due to leakage. In addition, an evaluation has been performed, NEDC-31339, "BWR Owners' Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," November 1986, that showed the probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to the reactor pressure is very low. Therefore, this change will not involve a significant increase in the probability or 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?

   The proposed change does not introduce a new mode of plant operation and does not involve a 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?

   The change to PIV leakage limits is acceptable since it recognizes the difference in allowable leakage based on valve size while assuring that leakage limits are maintained such that the probability for gross PIV failure is reduced. Additionally, the Technical Specification limitation total allowable RCS leakage continues to be maintained. Therefore, any reduction in a margin of safety will be insignificant, and offset by the benefit of avoiding an unnecessary maintenance when PIV leakage would not be indicative of gross PIV failure.

L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 would allow continued operation of the RHR Shutdown Cooling System with PIV leakage above the limits. However, this exception is provided only when the system is in operation i.e., only when the reactor coolant pressure has been reduced to below the RHR cut-in permissive pressure. Therefore, this change does not increase the probability of any accident previously evaluated. Additionally, the PIVs do not provide any accident mitigation functions once the Reactor Coolant System is depressurized. Therefore, the proposed change will not increase 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 proposed exception provides for the intended use of the primary system for decay heat removal.

 1C

L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change does not result in any hardware or operating procedure changes. The requirement to perform a leak test to verify the restoration of a PIV is not assumed in the initiation of any analyzed event. This requirement was specified in the Technical Specifications to ensure the leakage of a restored PIV was positively verified to be within limits following repair, maintenance, or replacement work that could affect the valve leakage rate. The proposed deletion of this explicit requirement is considered administrative since SR 3.0.1 requires the appropriate SRs to be performed to demonstrate OPERABILITY after restoration of a component that caused the SR to be failed. In this case, SR 3.0.1 would require SR 3.4.6.1 to be performed, which requires a leak test of the PIV be performed. As a result, the accident consequences are unaffected by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated. 1C

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

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   The proposed deletion of the explicit requirement to perform a leak test on the affected PIV following repair, maintenance, or replacement work that could affect the leak rate of the valve is considered administrative since SR 3.0.1 requires the appropriate SRs to be performed to demonstrate OPERABILITY after restoration of a component that caused the SR to be failed. In this case, SR 3.0.1 would require SR 3.4.6.1 to be performed, which requires a leak test of the PIV be performed. As a result, the existing requirement to perform a leak test on the affected PIV following repair, maintenance, or replacement work that could affect the leak rate of the valve is maintained. Therefore, this change does not involve a significant reduction in a margin of safety. 1C

## L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 would allow continued operation with inoperable leakage detection systems. The leakage detection systems are not considered as initiators of any previously evaluated accident. However, they do provide information to the operator of potential conditions that may be precursors to an accident. In the proposed conditions, sufficient indication will remain OPERABLE to provide the operator with the information necessary to evaluate the potential precursor conditions. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Additionally, the leakage detection systems do not provide any accident mitigation functions. Therefore, the proposed change will not increase 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 proposed LCO will maintain adequate indications to the operator, and in addition will continue to provide appropriate compensatory measures.

1C

## L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   Mode changes are proposed to be allowed with the drywell floor drain sump flow monitoring system or the required drywell atmospheric monitoring system inoperable. The RCS leakage detection instrumentation is not considered to be an initiator for any previously evaluated accident. Therefore, the probability of an accident previously evaluated is not significantly increased. However, they do provide information to the operator of potential conditions that may be precursors to an accident. In the proposed conditions, sufficient indication will remain OPERABLE to provide the operator with the information necessary to evaluate the potential precursor conditions. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Additionally, the leakage detection systems do not provide any accident mitigation functions. Therefore, the proposed change will not increase 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 proposed LCO will maintain adequate indications to the operator, and in addition will continue to provide appropriate compensatory measures.

## L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 change modifies the Surveillance to indicate when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other required Leakage Detection System channel is OPERABLE. The Leakage Detection System Instrumentation is not considered as an initiator for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Also, this change does not further degrade the capability of the monitors to perform their required function under these circumstances since one channel is still OPERABLE. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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 monitors are not required to provide automatic response to any design basis accident. The additional time does not significantly affect the contribution of the monitors to risk reduction since the function is still being monitored by the other OPERABLE channel.

 1A

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 deletes Technical Specification (TS) Limiting Condition for Operation (LCO) 3.4.5.b which requires that the reactor coolant gross specific activity remain less than or equal to 100/E-bar μCi/gm, and the Surveillance Requirements to determine gross beta/gamma activity at least once per 72 hours and to determine E-bar at least once per 6 months, Table 4.4.5-1, Items 1 and 3. The proposed change also deletes ACTION a.2 associated with LCO 3.4.5.b that requires the plant to be in HOT SHUTDOWN with the main steam isolation valves closed within 12 hours after the reactor coolant gross specific activity exceeds 100/E-bar μCi/gm.

   BWR operating experience has shown that as fuel leakage increases, dose equivalent iodine (DEI) approaches the TS limit much more rapidly than does the gross specific activity. The BWR design utilizes main condenser air ejectors to remove non-condensible gases from the reactor coolant. The non-condensible gases are then sampled, monitored, and processed by the Offgas Treatment System prior to release to the environment. The offgas pretreatment sample provides a more representative sample of the noble gases that would be released in the event of a main steam line failure outside containment than does the reactor coolant sample currently being taken from the Reactor Recirculation System. The offgas pretreatment monitor includes a setpoint which responds to release rates above a specified level which is established to ensure that untreated releases would not result in a whole body dose that exceeds a small fraction (10%) of the 10 CFR 100 limits. The sample points on the Reactor Recirculation (RRC) System and Reactor Water Cleanup (RWCU) System currently being used to collect information regarding gross specific activity will continue to be available for use in the event of a main steam line failure upstream of the Offgas Treatment System.

   The intent of the requirement to limit specific activity in the reactor coolant is to ensure that the whole body and thyroid doses at the site boundary will not exceed a small fraction of the 10 CFR 100 limits (i.e., 10 percent of 25 rem and 300 rem, respectively) in the event of a main steam line failure outside containment or an instrument line break. To ensure that offsite thyroid doses do not exceed 30 rem, reactor coolant DEI is limited to less than or equal to 0.2 μCi/gm. Likewise, reactor coolant gross specific activity is limited by current Technical Specifications to less than or equal to 100/E-bar μCi/gm to ensure that

 1C

L.1 CHANGE

1. (continued)

offsite whole body doses do not exceed 2.5 rem. Reactor coolant gross specific activity is not an initiator of any accident evaluated in the FSAR and therefore, deletion of LCO 3.4.5.b which limits reactor coolant gross specific activity to a value less than or equal to 100/E-bar $\mu$Ci/gm will not result in an increase in the probability of an accident previously evaluated in the FSAR.

Current LCO 3.11.2.7 (proposed LCO 3.7.5) associated with radioactive effluents requires that the gross gamma radioactivity rate of the noble gases Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 measured at the main condenser evacuation system pretreatment monitor station be limited to less than or equal to 332 mCi/second. The current Bases for LCO 3.11.2.7 state that restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total-body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the 10 CFR 100 limits in the event this effluent is inadvertently discharged without treatment directly to the environment.

The Offgas Treatment System, as required by current LCO 3.11.2.7 and proposed LCO 3.7.5, provides reasonable assurance the reactor coolant gross specific activity is maintained at a sufficiently low level to preclude offsite doses from exceeding a small fraction of the 10 CFR 100 limits in the event of a main steam line failure. Additional assurance that the offsite doses will not exceed a small fraction of the 10 CFR 100 limits is provided by increasing the frequency of sampling and analysis of the reactor coolant for DEI from at least once per 31 days to at least once per 7 days (proposed SR 3.4.8.1). Since the proposed change will ensure that the offsite doses resulting from a main steam line failure or an instrument line break will continue to be limited to a small fraction of the 10 CFR 100 limits, the proposed change will not involve a significant increase in the consequences of an accident previously evaluated. 1C

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 involve a physical modification to the plant or to plant operation. The reactor coolant gross specific activity is a parameter that is monitored to prevent offsite doses from exceeding a small fraction (10%) of the 10 CFR 100 limits and support calculation of offsite doses in the event of a main steam line failure outside containment. As such, the reactor coolant specific activity is utilized to mitigate the radiological consequences of a main steam line failure and is not considered to be an initiator for any accident.

L.1 CHANGE

2. (continued)

Additionally, the Offgas Treatment System will provide an equal or better means for monitoring the reactor coolant gross specific activity than would the RRC System currently being used for this purpose. In the event of a main steam line break upstream of the condenser that would prevent use of the Offgas Treatment System to monitor reactor coolant gross specific activity, the existing sample points on the RRC System and RWCU System would continue to be available. Accordingly, deletion of the requirement to limit reactor coolant gross specific activity will not create the possibility of a new or different kind of accident from any previously evaluated.

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

The intent of the requirement to limit specific activity in the reactor coolant is to ensure that the whole body and thyroid doses at the site boundary will not exceed a small fraction of the 10 CFR 100 limits (i.e., 10 percent of 25 rem and 300 rem, respectively) in the event of a main steam line failure outside containment or an instrument line break.

As stated above, current LCO 3.11.2.7 associated with radioactive effluents requires that the gross gamma radioactivity of the noble gases Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 measured at the main condenser evacuation system pretreatment monitor station be limited to less than or equal to 332 mCi/second. The current Bases for LCO 3.11.2.7 state that restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total-body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the 10 CFR 100 limits in the event this effluent is inadvertently discharged without treatment directly to the environment.

The Offgas Treatment System, as required by current LCO 3.11.2.7 and proposed LCO 3.7.5, provides reasonable assurance the reactor coolant gross specific activity is maintained at a level sufficiently to preclude offsite doses from exceeding a small fraction of the 10 CFR 100 limits in the event of a main steam line failure. Therefore, LCO 3.4.5.b is redundant and places an unnecessary burden on the licensee without a commensurate increase in the margin of safety. Elimination of LCO 3.4.5.b will allow plant personnel to focus attention on efficient, safe operation of the plant without the distraction of an unnecessary Surveillance Requirement. Accordingly, the proposed change enhances operation of the plant without reducing the margin of safety associated with a main steam line failure outside of containment (i.e., offsite doses remain a small fraction of the 10 CFR 100 limits).

 1C

L.1 CHANGE

3. (continued)

Additional assurance that the offsite doses will not exceed a small fraction of the 10 CFR 100 limits is provided by increasing the frequency of sampling and analysis of the reactor coolant for DEI from at least once per 31 days to at least once per 7 days (proposed SR 3.4.8.1). Therefore, the proposed change does not result in a significant reduction in a margin of safety. 1C

## L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 would limit the Applicability for specific activity to those conditions that have potential impact on the consequences of an accident. The specific activity is not considered as an initiator of any previously evaluated accident. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Specific activity is an assumption that must be met to limit the consequences of an accident. However, in MODE 4 there is no potential for leakage since the reactor is depressurized, and with the main steam lines isolated in MODES 2 and 3, there is no significant leakage path. Therefore, the proposed change will not increase 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 proposed conditions maintain Applicability of the appropriate limits for all conditions that represent potential to impact the consequences of any accident previously evaluated.

1C

## L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 would allow entry into the applicable conditions while depending on compliance with the ACTION. The specific activity is not considered as an initiator of any previously evaluated accident. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Specific activity is an assumption that must be met to limit the consequences of an accident. However, operation has been determined to be acceptable for a short period of time with the limits not met. The consequences of an accident while operating during the proposed period of time are the same as those while operating under the constraints of the ACTION which has previously been determined acceptable. Therefore, the proposed change will not increase 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 proposed period of time for operating beyond the limits has not changed.

## L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 allows time to place the system in service after reaching the applicable conditions. Since the system can not physically be placed in service until the cut-in permissive pressure setpoint is reached, this change only allows the activity to take place without resorting to intentional noncompliance with the requirements. Since no actual change to the operation of the plant is involved, the proposed change will not increase the probability or 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 introduces no new mode of plant operation and it 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 proposed change only allows time to conduct the necessary manipulations to place the required system in service.

There were no plant specific less restrictive changes identified for this Specification.

There were no plant specific less restrictive changes identified for this Specification.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.4.12 - REACTOR STEAM DOME PRESSURE

1C

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change would allow the reactor steam dome pressure limit to be raised an infinitesimally small amount to be equal to 1035 psig and still be within the limit. The reactor steam dome pressure is not considered an initiator of any previously analyzed accident. Therefore, this change does not significantly increase the probability of such accidents. The proposed change would allow continued operation at exactly 1035 psig. However, the consequences of an event that may occur at 1035 psig would not be any different than an event that occurs at slightly less than 1035 psig since the safety analyses assume the reactor steam dome pressure at the start of the accident is equal to 1035 psig, and the analyses show that the ASME limits are not exceeded during the overpressure transient. Therefore, this change does not significantly increase the consequences of any previously analyzed accident.

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 involve any design changes, plant modifications, or changes in plant operation. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

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

   This change would allow the reactor steam dome pressure limit to be raised an infinitesimally small amount to be equal to 1035 psig and still be within the limit. The safety analyses assume the reactor steam dome pressure at the start of the accident is equal to 1035 psig, and the analyses show that the ASME limits are not exceeded during the overpressure transient. Therefore, the change does not involve a significant reduction in the margin of safety.

L.3 CHANGE

Not used.

|C

L.4 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 removes the requirement to submit a Special Report for ECCS actuation because the reporting requirements can be met by an LER required by 10 CFR 50.73(a)(2)(iv) and plant procedures that track ECCS actuation cycle information. The proposed change does not increase the probability of an accident because it will not involve any physical changes to plant systems, structures, or components, or the manner in which these systems, structures, or components are operated, maintained, modified, tested, or inspected. The Special Report for ECCS actuation is not assumed to be an initiator of any analyzed event. Also, the consequences of an accident are not affected by this report since it does not impact the assumptions of any design basis accident or transient.

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?

   The margin of safety is not reduced by removing the requirement for the submittal of a special report for ECCS actuation. This proposed change has no effect on the assumptions of the design basis accident. This change also has no impact on the safe operation of the plant because equivalent information is tracked and available or reported through the LER process. This change does not affect any plant equipment or requirements for maintaining plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

L.5 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   ECCS equipment is used to mitigate the consequences of an accident, but is not considered as the initiator of any previously analyzed accident. As such the inoperability of ECCS systems will not increase the probability of any accident previously evaluated. The proposed ACTION is bounded by the analysis summarized in NEDC-31376P, and therefore, does not involve any increase to 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 proposed combination of inoperable ECCS has been previously evaluated and the length of the allowable outage time specified permitted is consistent with other comparable combinations of inoperable ECCS systems.

L.6 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 LPCI System is not assumed to be the initiator of any previously analyzed event. Its role is in mitigating and thereby limiting consequences of analyzed events. With this proposed change LPCI is still capable of being manually realigned if needed to mitigate the consequences of design basis accidents. In addition, the allowance is applicable when the reactor is shutdown in MODE 3, with the reactor pressure less than the RHR low pressure permissive pressure setpoint. Thus, the reactor heat load is much less than in MODE 1 (the MODE assumed in the accident analysis). Furthermore, the other subsystems of the ECCS are still required to be OPERABLE. Therefore, this change will not involve a significant increase in the probability or 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?

   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?

   The proposed change does not reduce a margin of safety because the change has no impact on any safety analysis assumption. The clarifying Note allows the decay heat removal function to be available without the immediate shutdown requirements for inoperable LPCI subsystems being imposed. This is in recognition that the amount of time to realign the LPCI System from the decay heat removal function has no significant impact on the margin of safety associated with establishing LPCI injection, because heat loads under these conditions are far below that assumed in the safety analysis.

## L.7 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 phrase "actual or," in reference to the automatic initiation signal, has been added to the system functional test surveillance test description. This does not impose a requirement to create an "actual" signal, nor does it eliminate any restriction on producing an "actual" signal. While creating an "actual" signal could increase the probability of an event, existing procedures and 10 CFR 50.59 control of revisions to them, dictate the acceptability of generating this signal. The proposed change does not affect the procedures governing plant operations and therefore the probability of creating these signals; it simply would allow such a signal to be credited when evaluating the acceptance criteria for the system functional test requirements. Therefore, the change does not involve a significant increase in the probability of an accident previously evaluated. Since the method of initiation will not affect the acceptance criteria of the system functional test, the change does not involve a significant 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   Use of an actual signal instead of the existing requirement, which limits use to a simulated signal, will not affect the performance or acceptance criteria of the surveillance test. OPERABILITY is adequately demonstrated in either case since the system itself cannot discriminate between "actual" or "simulated" signals. Therefore, the change does not involve a significant reduction in a margin of safety.

L.8 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change will allow the pressure of an individual ADS accumulator backup compressed gas system bottle to be < 2200 psig, provided the average pressure of all required bottles (which all have the same capacity) is ≥ 2200 psig. The analysis demonstrated that with average pressure ≥ 2200 psig, the nitrogen supply is sufficient to operate the ADS valves for 30 days. The ADS valves are not assumed to be an initiator of any analyzed event. ADS is assumed in the mitigation of consequences of a loss of coolant accident which occurs at high reactor vessel pressure. Since this capability is not affected there is no significant increase in the consequences of any previously analyzed accident.

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, the proposed change 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?

   Changing the minimum pressure for an individual nitrogen bottle does not involve a significant reduction in a margin of safety since a 30 day nitrogen supply is still being maintained; thus the ADS will continue to be capable of performing its function.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.6.2.3 - RHR SUPPRESSION POOL COOLING

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change would allow an additional 96 hours to restore one loop of suppression pool cooling when it is found to be inoperable. Suppression pool cooling is not considered an initiator of any previously analyzed accident. Therefore, this change does not significantly increase the frequency of such accidents. The proposed change would allow additional temporary operation with less than the required suppression pool cooling capability. However, since the only change is in the allowed outage time, the consequences of an event that may occur during the extended outage time would not be any different than during the currently allowed outage time. Therefore, this change does not significantly increase the consequences of any previously analyzed accident. |C

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

   This change does not result in any changes to the equipment design or capabilities, but does allow operation of the plant with equipment not capable of performing its safety function. However, loss of the suppression pool cooling function does not impact the reactor coolant pressure boundary or its support systems, and therefore, does not create the possibility of a new or different kind of accident from any previously analyzed accident.

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

   The change increases the allowed outage time. The margin of safety considered in determining the allowed outage time is based on engineering judgement and probability of occurrence of an event requiring the unavailable capabilities. The proposed 96 hour extension is based on similar current allowed outage times for emergency core cooling systems equipment. Therefore, the change does not involve a significant reduction in the margin of safety. |C

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.7.1 - STANDBY SERVICE WATER (SW) SYSTEM AND ULTIMATE HEAT SINK (UHS)

L.1 CHANGE

Not used. C

## L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change would remove a specific restriction to perform a Surveillance of the Standby Service Water System during shutdown. SW System actuations are not considered as initiators of any previously analyzed accident. Therefore, this change does not significantly increase the frequency of such accidents. The appropriate plant conditions for performance of the Surveillance will continue to be controlled to assure the potential consequences are not significantly increased. This control method has been previously determined to be acceptable as indicated in Generic Letter 91-04. Therefore, this change does not significantly increase the consequences of any previously analyzed accident.

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

   This change removes a specific restriction on the plant conditions for performing a Surveillance, but does not change the method of performance. The appropriate plant conditions for performance of the Surveillance will continue to be controlled to assure the possibility for a new or different kind of accident are not created. This control method has been previously determined to be acceptable as indicated in Generic Letter 91-04. Therefore, this change does not create the possibility of a new or different kind of accident from any previously analyzed accident.

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

   The margin of safety considered in determining the appropriate plant conditions for performing the Surveillance will continue to be controlled to assure that there is no significant reduction. This control method has been previously determined to be acceptable as indicated in Generic Letter 91-04. Therefore, the change does not involve a significant reduction in the margin of safety.

L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 phrase "actual or," in reference to the actuation test signal has been added to the system functional test Surveillance test description. This does not impose a requirement to create an "actual" signal, nor does it eliminate any restriction on producing an "actual" signal. While creating an "actual" signal could increase the probability of an event, existing procedures (and the 10 CFR 50.59 control of revisions to them) dictate the acceptability of generating this signal. The proposed change does not affect the procedures governing plant operations or the acceptability of creating these signals; it simply would allow such a signal to be utilized in evaluating the acceptance criteria for the system functional test requirements. Therefore, the change does not involve a significant increase in the probability of an accident previously evaluated. Since the method of initiation will not affect the acceptance criteria of the system functional test, the change does not involve a significant 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   Use of an actual signal instead of the existing requirement, which limits use to a test signal, will not affect the performance or acceptance criteria of the Surveillance test. OPERABILITY is adequately demonstrated in either case since the system itself can not discriminate between "actual" or "test" signals. Therefore, the change does not involve a significant reduction in a margin of safety.

## L.3 CHANGE

Not used.

C

## L.4 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 AC Sources 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, additional time for repair of an inoperable AC Source will not increase the probability of any accident previously evaluated. The proposed ACTION continues to provide adequate assurance of OPERABLE AC Sources 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 AC Sources continues to be required. Overlapping inoperabilities of the AC Sources are expected to be infrequent, and any reduction due to the extended time frame is off-set by not subjecting the plant to a shutdown transient.

L.5 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 DGs are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. Furthermore, equipment powered by the DGs, which may be considered as an initiator, continues to be evaluated for loss of function and previously determined appropriate ACTIONS for such inoperabilities continue to be required. As such the proposed increase in the Completion Time will not increase the probability of any accident previously evaluated. The proposed ACTION continues to provide adequate assurance of OPERABLE required equipment 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 equipment and loss of function continue to be evaluated in the same manner. The increase in time allowed for such a evaluation is minimal and provides additional potential for preferred restoration of the equipment to OPERABLE status rather than requiring a shutdown transient.

## L.6 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 DGs are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. Furthermore, equipment powered by the DGs, which may be considered as an initiator, continue to be evaluated for loss of function, and previously determined appropriate ACTIONS for such inoperabilities continue to be required. As such, the proposed ACTION will not increase the probability of any accident previously evaluated. The proposed ACTION continues to provide adequate assurance of OPERABLE required equipment 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 determination of loss of function continues to be determined in the same manner.

## L.7 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 elimination of a requirement to stagger the surveillance testing will not increase the probability of any accident previously evaluated. The proposed SR continues to provide 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 continues to be determined in the same manner. Staggered testing does not have a significant effect on reliability, and does not impact the capability of the DGs to perform their safety function. Since the DG power sources are independent and common failure cause is evaluated, the proposed change provides an equivalent assurance of the capability of the DGs to perform their safety function.

## L.8 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This requested amendment does not result in any hardware or operating procedure changes. 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 in excess of 3 hours 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 92 day fuel oil transfer pump frequency is consistent with 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.

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 92 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.

L.9 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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, allowing engine prelube prior to start testing will not increase the probability of any accident previously evaluated. The proposed SR continues to provide 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 engine prelube does not result in enhanced start performance which could mask the DGs' ability to start in accident conditions without a prelube.

L.10 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 consequence of an accident previously evaluated?

   The DGs are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. The DGs are still tested to ensure their capability to mitigate the consequences of an accident. 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. Since the steady state limit requirements have not been changed, and the minimum voltage and frequency limits still ensure the DG can tie to the bus, this change does not involve an increase in the consequences of a previously analyzed accident.

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 proposed testing still ensures the DGs can perform their intended function. The allowance to overshoot the upper voltage and frequency bands does not impact the capability of the DG, provided the minimum voltage and frequency are met within the assumed time, and the steady state limits are reached and maintained. These limits are not being modified. In addition, other DG tests will continue to show capability of the DGs to start and accept loads while maintaining proper voltage and frequency.

L.11 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 DGs are not assumed to be an initiator of any analyzed event. The DGs function to mitigate consequences of an analyzed event by supplying sufficient power to equipment assumed to function during an accident. The change to the Surveillance still provides assurance the DGs are capable of synchronizing and carrying loads. Full load carrying capability is demonstrated on a 24 month basis and the load capability and required loads do not change without requiring performance of the 24 month full load test (post maintenance practices). Therefore, adequate assurance the DG is capable of carrying the required accident load is provided by the 24 month test and need not be repeated once per 31 days. The change will help enhance DG reliability and availability by ensuring the continuous rating is not required to be exceeded on a 31 day basis. Therefore, this change will not involve a significant increase in the probability or 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?

   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 the change involve a significant reduction in a margin of safety?

   No significant reduction in a margin of safety is involved with this change since, based on operating experience, adequate assurance of DG full load carrying capability is provided by the 24 month test. Additionally, any potential changes to DG load carrying capability due to maintenance or modification or any changes to required loads would require the full load test to be performed to demonstrate OPERABILITY. Any reduction in a margin of safety would be offset by the enhanced DG reliability and availability gained by not requiring the continuous rating to be exceeded on a 31 day basis.

L.12 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 elimination of a time requirement to load the DG during surveillance testing will not increase the probability of any accident previously evaluated. The proposed SR continues to provide 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 manual loading of the DGs does not impact the capability of the DGs to perform their safety function.

L.13 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 requested amendment does not result in any hardware or operating procedure changes. Diesel fuel oil properties are not assumed to be an initiator of any analyzed event. Diesel fuel oil supports the operation of the DGs. As such, it mitigates consequences of a design basis accident by helping to assure the DGs supply power to equipment assumed to function during an accident. The change to the diesel fuel oil check for accumulated water Surveillance Frequency still provides adequate assurance that diesel fuel oil remains capable of supporting DG OPERABILITY. Therefore, this proposed change will not involve a significant increase in the probability or 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?

   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 the 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 is adequate for assuring water does not accumulate in the day tanks. Additionally, water content of the fuel oil in the fuel oil storage tanks is checked prior to addition of new fuel and once per 92 days. As such, assurance is provided that the water content of diesel fuel oil in the day tank is within limits and that the diesel fuel oil remains capable of supporting DG OPERABILITY.

## L.14 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 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 revised criteria for determining failure of the required Surveillance (i.e., allowing momentary load transients) will not increase the probability of any accident previously evaluated. The proposed criteria provide adequate assurance of OPERABLE DGs and therefore, do not involve any increase to 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 continues to be determined based on their capability to perform their safety related function.

L.15 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 as the initiator of any previously analyzed accident. As such, the elimination of a specific signal requirement to perform the "hot restart" surveillance testing or the automatic loading requirement after starting will not increase the probability of any accident previously evaluated. The proposed SR continues to provide adequate assurance of OPERABLE DGs since restart capability is not affected by the start signal. In addition, the automatic loading requirement continues to be proven during other required Surveillance Requirements (e.g., the LOOP and LOOP/LOCA tests). Therefore, the proposed change 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 start capability of the DGs is not affected by the start signal and other required SRs continue to prove automatic loading capability. Therefore, the proposed change provides an equivalent assurance of the capability of the DGs to perform their safety function.

## L.16 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 phrase "actual or," in reference to the automatic loss of offsite power signal or ECCS actuation signal, as applicable, has been added to the system functional test surveillance test description. This does not impose a requirement to create an "actual" signal, nor does it eliminate any restriction on producing an "actual" signal. While creating an "actual" signal could increase the probability of an event, existing procedures (and the 10 CFR 50.59 control of revisions to them) dictate the acceptability of generating this signal. The proposed change does not affect the procedures governing plant operations or the acceptability of creating these signals; it simply would allow such a signal to be utilized in evaluating the acceptance criteria for the system functional test requirements. Therefore, the change does not involve a significant increase in the probability of an accident previously evaluated. Since the method of initiation will not affect the acceptance criteria of the system functional test, the change does not involve a significant 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?

   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?

   Use of an actual signal instead of the existing requirement, which limits use to a test signal will not affect the performance or acceptance criteria of the Surveillance. Operability is adequately demonstrated in either case since the system itself can not discriminate between "actual" or "test" signals. Therefore, the change does not involve a significant reduction in a margin of safety.

L.17 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System has evaluated this proposed Technical Specification change and has 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?

   This change does not result in any hardware or operating procedure changes. The requirement to perform the interdependence test after any modification that could affect diesel generator interdependence is not assumed in the initiation of any analyzed event. This requirement was specified in the Technical Specifications to ensure the independence of the diesel generators was positively verified following modifications that could impact diesel generator independence. The proposed deletion of this explicit requirement is considered administrative since SR 3.0.1 requires the appropriate SRs to be performed to demonstrate OPERABILITY after restoration of a component that caused the SR to be failed. In this case, SR 3.0.1 would require SR 3.8.1.20 to be performed which requires performance of the diesel generator interdependence test. As a result, the accident consequences are unaffected by this change. Therefore, this change will not involve a significant increase in the probability or 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?

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   The proposed deletion of the explicit requirement to perform the interdependence test after any modification that could affect diesel generator interdependence is considered administrative since SR 3.0.1 requires the appropriate SRs to be performed to demonstrate OPERABILITY after restoration of a component that caused the SR to be failed. In this case, SR 3.0.1 would require SR 3.8.1.20 to be performed which requires performance of the diesel generator interdependence test. As a result, the existing requirement to perform the interdependence test after any modification that could affect diesel generator interdependence is maintained. Therefore, this change does not involve a significant reduction in a margin of safety.

L.18 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 Division 3 diesel generator (DG) is used to support mitigation of the consequences of an accident; however, it is not considered the initiator of any previously analyzed accident. As such, the revised acceptance criteria for voltage, frequency, and start time will not increase the probability of any accident previously evaluated. The new criteria is consistent with the other Surveillances, which have been determined to be sufficient to demonstrate OPERABILITY, and are consistent with the accident analyses. Therefore, since the DG will continue to be tested to show that it meets the assumptions of the accident analysis, the change does not involve any increase to 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 DG continues to be determined based on its capability to perform its safety related function. The new acceptance criteria is consistent with the other DG Surveillances and with the accident analyses.

## L.19 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change proposes to remove the Technical Specification requirement for submitting a special report after DG failures. This change is consistent with Generic Letter 94-01, which allows the removal of this requirement from Technical Specifications. The submittal of the special report for DG failures is not assumed to be an initiator of any analyzed event. Also, the consequences of an accident are not affected by this report since it does not impact the assumptions of any design basis accident or transient.

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 proposes to remove the Technical Specification requirement for submitting a special report after DG failures. This change is consistent with Generic Letter 94-01, which allows the removal of this requirement from Technical Specifications. The margin of safety is not reduced by removing the requirement for the submittal of a special report after DG failures from the Technical Specifications. This proposed change has no effect on the assumptions of the design basis accident. This change has no impact on the safe operation of the plant because the report is submitted after DG failures have occurred and does not require NRC approval. The NRC will still be required to be notified of DG failures per the requirements of 10 CFR 50.72 and 50.73, as applicable. This change does not affect any plant equipment or requirements for maintaining plant equipment. The safety analysis assumptions will still be maintained. Therefore, this change does not involve a significant reduction in a margin of safety.

L.20 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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 current surveillance requirements have been changed to update the diesel generator (DG) start and load times. The proposed changes increase the start time for the Division 1 DG (DG-1) and the Division 2 DG (DG-2) to rated voltage and frequency, or to load connection, from 10 seconds to 15 seconds. The proposed changes also increase the start and load time for DG-3 from 13 to 15 seconds for other than a loss of offsite power start signal by itself. For a loss of offsite power start signal by itself, the proposed changes increase the DG-3 start and load time from 13 to 18 seconds. On a loss of offsite power start signal by itself, the DG-3 start logic includes an additional 3 second time delay prior to initiation of the DG breaker close signal, which accounts for the difference between the start and load times for DG-1 and DG-2, and DG-3 for this unique condition. The 3 second time delay for DG-3 is automatically bypassed on an Emergency Core Cooling System (ECCS) initiation start signal . Thus, for loss of coolant accident (LOCA) conditions and ECCS considerations, the start time for all three DGs will be 15 seconds. The changes to the DG start and load times are based on the relaxed response times assumed for Emergency Core Cooling System (ECCS) parameters in the 10 CFR 50.46 and 10 CFR 50, Appendix K analyses (SAFER/GESTR-LOCA analysis) performed in support of the WNP-2 power uprate approved by the NRC in an Amendment dated May 2, 1995.

   The DGs provide emergency standby AC electrical power to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. The proposed changes to the DG start and load times do not change the DG design, the mode of operation or maintenance, and are not a physical modification to the plant, nor do the changes reduce the effectiveness of the surveillance requirements to demonstrate DG operability, detect equipment degradation, or assure reliability since the surveillance requirements continue to satisfy the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977, which are the bases for the current surveillance requirements. Moreover, the proposed changes will not affect current commitments related to DG reliability and the Maintenance Rule which are designed to identify and correct equipment deficiencies and degradation to maintain DG operability and reliability. Therefore, the proposed changes will not involve a significant increase in the probability of any accident previously evaluated.

L.20 CHANGE

1. (continued)

The proposed relaxation of the DG start times are the result of a change in the plant design basis. Since the proposed DG start and loading times are included in the assumptions for the NRC approved design basis SAFER/GESTR-LOCA analysis, the new start times will not affect the capability of the DGs to support equipment required to mitigate the consequences of the design basis event (i.e., a large break LOCA coincident with a loss of offsite power). Accident radiological dose calculations were performed to meet the recommendations of Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors." This guide requires an assumption that a certain percentage of the radiological material available in the fuel be immediately available for leakage from containment. To release such a fraction would require the fuel peak cladding temperature (PCT) to exceed the 10 CFR 50.46 limit of 2200° F for a significant period of time. The SAFER/GESTR-LOCA analysis for WNP-2 demonstrated that the PCT would be limited to 1440° F. Thus, the NRC assumption for the radiological calculations is non-mechanistic and very conservative. Since the proposed changes in the DG start times do not change the inventory of material or source term available for release per this assumption, there will be no impact on the consequences of the postulated LOCA or dose calculations. Therefore, the proposed changes will not involve a significant increase 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?

As discussed in the response to Question 1, the proposed changes increase the DG-1 and DG-2 start time to rated voltage and frequency, or to load connection, from 10 seconds to 15 seconds. For DG-3, the proposed changes increase the start and load time from 13 to 15 seconds for other than a loss of offsite power start signal by itself. For a loss of offsite power start signal by itself, the proposed changes increase the DG-3 start time from 13 to 18 seconds due to the additional 3 second time delay within the start logic that is only included for this unique condition. These changes do not involve a change to the DG design, the mode of operation or maintenance, and are not a physical modification to the plant, nor do the changes reduce the effectiveness of the surveillance requirements to demonstrate DG operability, detect equipment degradation, or assure reliability. The proposed changes have been evaluated for impact on the current NRC approved design basis SAFER/GESTR-LOCA analysis. The new DG start times are consistent with the assumptions of the analysis and plant equipment will not be operated nor respond in a manner that is different from the previously evaluated design basis LOCA event. Since plant design, operational methods, and equipment responses are unchanged, no new failure modes or accidents will be created. Therefore, the proposed changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

L.20 CHANGE (continued)

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

As discussed in the response to Question 1, the proposed changes increase the DG-1 and DG-2 start time to rated voltage and frequency, or to load connection, from 10 seconds to 15 seconds. For DG-3, the proposed changes increase the start and load time from 13 to 15 seconds for other than a loss of offsite power start signal by itself. For a loss of offsite power start signal by itself, the proposed changes increase the DG-3 start and load time from 13 to 18 seconds due to the additional 3 second time delay within the start logic that is only included for this unique condition. These proposed changes are consistent with the assumptions in the current design basis NRC approved SAFER/GESTR-LOCA analysis. The analysis assumes 15 second start and load times for all three DGs, consistent with the proposed times for ECCS initiation coincident with a loss of offsite power, to demonstrate conformance with the ECCS acceptance criteria of 10 CFR 50.46 and Appendix K. The Licensing Basis PCT for WNP-2 is currently 1440° F based on the analysis, which is well below the PCT limit of 2200° F. Therefore, WNP-2 meets the NRC licensing requirements for the SAFER/GESTR-LOCA analysis with 15 second DG start and load times. Since the DG start and loading times assumed in the design basis accident analysis are unchanged, there will be no affect on the capability of the DGs to support equipment required to mitigate the consequences of the design basis event (i.e., a large break LOCA coincident with a loss of offsite power). Furthermore, the proposed changes will not reduce the effectiveness of the surveillance requirements to demonstrate DG operability, detect equipment degradation, or assure reliability since the changes continue to satisfy the recommendations that serve as the bases for the surveillance requirements.

As discussed in Question 1, accident radiological dose calculations were performed to meet the recommendations of Regulatory Guide 1.3, which requires an assumption that a certain percentage of the radiological material available in the fuel be immediately available for leakage from containment. To release such a fraction would require the fuel PCT to exceed the 10 CFR 50.46 limit of 2200° F for a significant period of time. The LOCA analysis for WNP-2 demonstrated that the PCT would be limited to 1440° F. Thus, the NRC assumption for the radiological calculations is non-mechanistic and very conservative. Since the proposed changes in the DG start times do not change the inventory of material or source term available for release per this assumption, there will be no impact on the dose calculations or margins to the 10 CFR 100 guidelines. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

## L.1 CHANGE

Not used.

## L.2 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   An AC Source is necessary to support the equipment used to mitigate the consequences of an accident; however, the AC Source is not considered the initiator of any previously analyzed accident. As such, the proposed revision to the Surveillance Requirements will not increase the probability of any accident previously evaluated. The proposed SRs continue to provide adequate assurance of OPERABLE DGs and available offsite circuits 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 proposed change removes requirements for paralleling the required DG to the required offsite circuit. Omitting this condition represents a significant improvement in the margin of safety by removing the potential for a single fault to affect both required AC power sources.

## L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, the Supply System 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?

   This change proposes to remove the Technical Specification requirement for submitting a special report after DG failures. This change is consistent with Generic Letter 94-01, which allows the removal of this requirement from Technical Specifications. The submittal of the special report for DG failures is not assumed to be an initiator of any analyzed event. Also, the consequences of an accident are not affected by this report since it does not impact the assumptions of any design basis accident or transient.

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 proposes to remove the Technical Specification requirement for submitting a special report after DG failures. This change is consistent with Generic Letter 94-01, which allows the removal of this requirement from Technical Specifications. The margin of safety is not reduced by removing the requirement for the submittal of a special report after DG failures from the Technical Specifications. This proposed change has no effect on the assumptions of the design basis accident. This change has no impact on the safe operation of the plant because the report is submitted after DG failures have occurred and does not require NRC approval. The NRC will still be required to be notified of DG failures per the requirements of 10 CFR 50.72 and 50.73, as applicable. This change does not affect any plant equipment or requirements for maintaining plant equipment. The safety analysis assumptions will still be maintained. Therefore, this change does not involve a significant reduction in a margin of safety.

# VOLUME 8

1.1 Definitions

<TSTF-03 changes not shown> 7 1B

| | |
|---|---|
| DOSE EQUIVALENT I-131 (continued) | conversion factors used for this calculation shall be those listed in *Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites" ~~or those listed in~~ Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977 or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity"*. 1 ; 2 |
| EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME | The ECCS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS initiation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. |
| END OF CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM RESPONSE TIME | The EOC-RPT SYSTEM RESPONSE TIME shall be that time interval from initial signal generation by *the associated turbine ~~stop~~ throttle valve limit switch or from when the turbine ~~control~~ governor valve hydraulic ~~oil~~ control oil pressure drops below the pressure switch setpoint* to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured ~~[except for the breaker arc suppression time, which is not measured but is validated to conform to the manufacturer's design value]~~. 3 2 4 |
| ISOLATION SYSTEM RESPONSE TIME | The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation initiation setpoint at the channel sensor until the isolation valves travel to their required positions. ~~Times shall include diesel generator starting and sequence loading~~ 5 C |

(continued)

C

## 1.1 Definitions

| | |
|---|---|
| ISOLATION SYSTEM RESPONSE TIME (continued) | 5 ~~delays, where applicable~~. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. |
| ~~$L_a$~~ | ~~The maximum allowable primary containment leakage rate, $L_a$, shall be [ ]% of primary containment air weight per day at the calculated peak containment pressure ($P_a$).~~ 10 B |
| LEAKAGE | LEAKAGE shall be: |

a. Identified LEAKAGE

1. LEAKAGE into the drywell such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or

2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE;

b. Unidentified LEAKAGE

All LEAKAGE into the drywell that is not identified LEAKAGE;

c. Total LEAKAGE

Sum of the identified and unidentified LEAKAGE; and 2

d. Pressure Boundary LEAKAGE

LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.

| | |
|---|---|
| [LINEAR HEAT GENERATION RATE (LHGR) | The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.] 1 |

(continued)

1.1 Definitions (continued)

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Chapter 14, Initial Test Program of the FSAR; 1

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

~~PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)~~

~~The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.11, "RCS Pressure and Temperature (P/T) Limits."~~ 8

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~3833~~ 3486 MWt. 1

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

SHUTDOWN MARGIN (SDM)

SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that:

a. The reactor is xenon free;

b. The moderator temperature is 68°F; and

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
CHAPTER 1.0 - USE AND APPLICATION

1. The brackets have been removed and the proper plant specific information has been provided.

2. Typographical/grammatical error corrected.

3. The correct plant specific nomenclature has been provided.

4. This optional allowance has been deleted. WNP-2 measures the breaker arc suppression time.

5. The ISOLATION SYSTEM RESPONSE TIME definition has been modified to not include the diesel generator starting and loading times. These times have been deleted since they are redundant to the diesel generator Surveillance Requirements in LCO 3.8.1, AC Sources—Operating. This deletion was recommended in both NUREG-1366 and Generic Letter 93-05.

6. An acronym has been provided for fraction of limiting power density (FLPD), consistent with the acronym provided in the applicable LCO (LCO 3.2.4).

7. Generic change TSTF-03 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

8. The utilization of a Pressure and Temperature Limits Report (PTLR) requires the development, and NRC approval, of detailed methodologies for future revisions to P/T limits. At this time, the Supply System does not have the necessary methodologies submitted to the NRC for review and approval. Therefore, the proposed presentation removes references to the PTLR and proposes that the specific limits and curves be included in the P/T Limits Specification (LCO 3.4.11).

9. The currently licensed manner in which TURBINE BYPASS SYSTEM RESPONSE TIME testing is performed has been provided.

10. A Primary Containment Leakage Rate Testing Program has been added to Section 5.5, consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements. The Program includes the definition of $L_a$, therefore the definition in Section 1.1 is not needed.

## 1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

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

C

(continued)

## 1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

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

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

EXAMPLE 1.3-6

ACTIONS

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

(continued)

# 3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

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

Exceptions to this Specification are stated in the individual Specifications. These exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered allow unit operation in the MODE or other specified condition in the Applicability only for a limited period of time.

LCO 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, and 3.

~~Reviewer's Note: LCO 3.0.4 has been revised so that changes in MODES or other specified conditions in the Applicability that are part of a shutdown of the unit shall not be prevented. In addition, LCO 3.0.4 has been revised so that it is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, and 3. The MODE change restrictions in LCO 3.0.4 were previously applicable in all MODES. Before this version of LCO 3.0.4 can be implemented on a plant-specific basis, the licensee must review the existing technical specifications to determine where specific restrictions on MODE changes or Required Actions should be included in individual LCOs to justify this change; such an evaluation should be summarized in a matrix of all existing LCOs to facilitate NRC staff review of a conversion to the STS.~~

1

LCO 3.0.5

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

2

(continued)

## 3.1 REACTIVITY CONTROL SYSTEMS

### 3.1.5 Control Rod Scram Accumulators

LCO 3.1.5 Each control rod scram accumulator shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

---

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| A. One control rod scram accumulator inoperable with reactor steam dome pressure ≥ ~~[~~900~~]~~ psig. | A.1 | -----NOTE----- Only applicable if the average scram times of the two-by-two arrays ~~the~~ associated with the control rod ~~scram time was~~ with the inoperable accumulator are within the limits of Table 3.1.4-1 during the last scram time Surveillance. ------------- ~~Declare the associated control rod scram time "slow."~~ Declare the average scram time in all two-by-two arrays associated with the control rod with the inoperable accumulator not within the limits of Table 3.1.4-1 and declare the associated control rod "slow." | 8 hours |
| | OR | | |
| | A.2 | Declare the associated control rod inoperable. | 8 hours |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| B. Two or more control rod scram accumulators inoperable with reactor steam dome pressure ≥ {900} psig. 1 | B.1 | Restore charging water header pressure to ≥ ~~{1520}~~ 940 psig. 1 | 20 minutes from discovery of Condition B concurrent with charging water header pressure < ~~{1520}~~ 940 psig 1 |
| | AND | | |
| | B.2.1 | --------NOTE--------- Only applicable if the average scram times of the two-by-two arrays with the ~~the~~ associated control rod with the inoperable accumulator are ~~scram time was~~ within the limits of Table 3.1.4-1 during the last scram time Surveillance. 3 --------------------- Declare the average scram time in all two-by-two arrays associated with the control rod with the inoperable accumulator not within the limits of Table 3.1.4-1 and declare the associated control rod "slow." ~~Declare the associated control rod scram time "slow."~~ | 1 hour |
| | OR | | |
| | B.2.2 | Declare the associated control rod inoperable. | 1 hour |
| C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < {900} psig. 1 | C.1 5 | Verify ~~all~~ the control rod~~s~~ ~~associated~~ with ~~inoperable accumulators are~~ is fully inserted. | Immediately upon discovery of charging water header pressure < ~~{1520}~~ 940 psig 1 |
| | AND | | |

(continued)

C

B

## 3.3 INSTRUMENTATION

### 3.3.1.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or more required channels inoperable. | A.1 Place channel in trip.<br><br>OR<br><br>A.2 Place associated trip system in trip. | 12 hours<br><br><br><br>12 hours |
| B. One or more Functions with one or more required channels inoperable in both trip systems. | B.1 Place channel in one trip system in trip.<br><br>OR<br><br>B.2 Place one trip system in trip. | 6 hours<br><br><br><br>6 hours |
| C. One or more Functions with RPS trip capability not maintained. | C.1 Restore RPS trip capability. | 1 hour |

(continued)

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.3.1.1.16 12 | Verify Turbine Stop Throttle Valve — Closure, ~~Trip Oil Pressure—Low~~ 8 and Turbine Control Governor 8 Valve Fast Closure Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 40 30 2 % RTP. | 18 2 months |
| SR 3.3.1.1.17 15 4 | ---NOTES--- 1. Neutron detectors are excluded. 2. For Function 6 5 3, "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits. | 18 24 2 months on a STAGGERED TEST BASIS |

MOVE TO PREVIOUS PAGE 7

1 C

C

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER TRIP SYSTEM | CONDITIONS REFERENCED FROM REQUIRED ACTION D.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 1. Intermediate Range Monitors | | | | | |
| a. Neutron Flux — High | 2 | ~~[3]~~ 2 | G | SR 3.3.1.1.1<br>SR 3.3.1.1.3<br>SR 3.3.1.1.5<br>SR 3.3.1.1.6<br>SR 3.3.1.1.10<br>SR 3.3.1.1.14 | ≤ ~~[120/125]~~ 122/125 divisions of full scale |
| | 5[(a)] | ~~[3]~~ 2 | H | SR 3.3.1.1.1<br>SR 3.3.1.1.4<br>SR 3.3.1.1.10<br>SR 3.3.1.1.14 | ≤ ~~[120/125]~~ 122/125 divisions of full scale |
| b. Inop | 2 | ~~[3]~~ 2 | G | SR 3.3.1.1.3<br>SR 3.3.1.1.14 | NA |
| | 5[(a)] | ~~[3]~~ 2 | H | SR 3.3.1.1.4<br>SR 3.3.1.1.14 | NA |
| 2. Average Power Range Monitors | | | | | |
| a. Neutron Flux — High, Setdown | 2 | ~~[2]~~ 2 | G | SR 3.3.1.1.1<br>SR 3.3.1.1.3<br>SR 3.3.1.1.6<br>SR 3.3.1.1.7<br>SR 3.3.1.1.9<br>SR 3.3.1.1.14 | ≤ ~~[20]~~% RTP |
| b. Flow Biased Simulated Thermal Power — High | 1 | ~~[2]~~ 2 | F | SR 3.3.1.1.1<br>SR 3.3.1.1.2<br>~~SR 3.3.1.1.3~~<br>SR 3.3.1.1.7<br>SR 3.3.1.1.8<br>SR 3.3.1.1.9<br>SR 3.3.1.1.11<br>SR 3.3.1.1.14<br>~~SR 3.3.1.1.17~~ | ~~≤ [0.66 W + 67]% RTP and ≤ [113]% RTP[(b)]~~<br>≤ .58W + 62% RTP and ≤ 114.9% RTP |

(continued)

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

~~(b) Allowable Value is [≤ 0.66 W + 43%] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."~~

(14) INSERT BWR/4 3.3.2.1
(continued)



ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| C. (continued) | C.2.1.1 Verify ≥ 12 rods withdrawn.<br><br>OR<br><br>C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year.<br><br>AND<br><br>C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff. | Immediately<br><br><br><br>Immediately<br><br><br><br>During control rod movement |
| D. RWM inoperable during reactor shutdown.<br><br>(13) compliance | D.1 Verify movement of control rods is in accordance with BPWS by a second licensed operator or other qualified member of the technical staff. | During control rod movement |

10

(continued)



Insert Page 3.3-19b

(14) INSERT BWR/4 3.3.2.1 (continued)



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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|
| 1. Rod Block Monitor | | | | |
| a. Low Power Range — Upscale | (a) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.4<br>SR 3.3.2.1.8 (7)(5) | ≤ [115.5/125] divisions of full scale 0.58w + 51% RTP (2) |
| b. Intermediate Power Range — Upscale | (b) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.4<br>SR 3.3.2.1.7 | ≤ [109.7/125] divisions of full scale |
| c. High Power Range — Upscale | (c),(d) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.4<br>SR 3.3.2.1.7 | ≤ [105.9/125] divisions of full scale |
| b d. Inop | (a) (d),(e) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.4 (16) | NA |
| c e. Downscale | (a) (d),(e) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.8 (7)(5) | ≥ [93/125] divisions of full scale 3% RTP (2) |
| f. Bypass Time Delay | (d),(e) | [2] | SR 3.3.2.1.1<br>SR 3.3.2.1.7 | ≤ [2.0] seconds |
| 2. Rod Worth Minimizer | 1(b)(f),2(b)(f) | [1] | SR 3.3.2.1.2<br>SR 3.3.2.1.3<br>SR 3.3.2.1.5 (6)(7)<br>SR 3.3.2.1.8 | NA |
| 3. Reactor Mode Switch — Shutdown Position | (c)(g) | [2] | SR 3.3.2.1.6 (7) | NA |

(16) (a) THERMAL POWER ≥ (30) ~~[29]~~% RTP and no peripheral control rod selected. ~~and ≤ [64]% RTP and MCPR < [1.70].~~

(16) ~~(b) THERMAL POWER > [64]% and ≤ [84]% RTP and MCPR < 1.70.~~

~~(c) THERMAL POWER > [84]% and < 90% RTP and MCPR < 1.70.~~

~~(d) THERMAL POWER ≥ 90% RTP and MCPR < 1.40.~~

~~(e) THERMAL POWER ≥ [64]% and < 90% RTP and MCPR < 1.70.~~

(16) (b) ~~(f)~~ With THERMAL POWER ≤ [10]% RTP. (2)

(c) ~~(g)~~ Reactor mode switch in the shutdown position.



Insert Page 3.3-19f

1C

## 3.3 INSTRUMENTATION

### 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

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

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

-------------------------------------------------------------------------------

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| A. One or more Functions with one required channel inoperable. | A.1 | Restore required channel to OPERABLE status. | 30 days |
| B. Required Action and associated Completion Time of Condition A not met. | B.1 | Initiate action in accordance with Specification 5.6.~~8~~ 6. 17 | Immediately 1C |
| C. 18 ~~------NOTE------ Not applicable to [hydrogen monitor] channels. ----------------~~ One or more Functions with two or more required channels inoperable. 19 | C.1 | Restore all but one required channel to OPERABLE status. 19 | 7 days |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| ~~D. Two [required hydrogen monitor] channels inoperable.~~ 18 | ~~D.1 Restore one [required hydrogen monitor] channel to OPERABLE status.~~ | ~~72 hours~~ |
| ~~E~~ D. Required Action and associated Completion Time of Condition C ~~or D~~ not met. 18 | ~~E~~ D.1 Enter the Condition referenced in Table 3.3.3.1-1 for the channel. 18 | Immediately |
| ~~F~~ E. As required by Required Action ~~E~~ D.1 18 and referenced in Table 3.3.3.1-1. | ~~F~~ E.1 Be in MODE 3. | 12 hours |
| ~~G~~ F. 18 As required by Required Action ~~E~~ D.1 18 and referenced in Table 3.3.3.1-1. 2 | ~~G~~ F.1 Initiate action in accordance with Specification 5.6.~~8~~ 6 17 | Immediately |

1C

## 3.3 INSTRUMENTATION

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

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

a. Reactor Vessel Water Level — Low Low, Level 2; and

b. Reactor Steam Dome Pressure — High.

Vessel 8

APPLICABILITY: MODE 1.

ACTIONS

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

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or more channels inoperable. | A.1 Restore channel to OPERABLE status. | 14 days 7 45 |
| | <u>OR</u> | |
| | A.2 --------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. --------------------- Place channel in trip. | 7 14 days |

C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.3.4.2.2 | Perform CHANNEL FUNCTIONAL TEST. | ~~[92]~~ days 2 |
| 6 ~~SR 3.3.4.2.3~~ | ~~Calibrate the trip units.~~ | ~~[92] days~~ |
| SR 3.3.4.2.~~4~~ 3 6 | Perform CHANNEL CALIBRATION. The Allowable Values shall be:<br>a. Reactor Vessel Water Level—Low Low, Level 2: ≥ ~~[−43.8]~~ −58 inches; and 2<br>b. Reactor Vessel Steam Dome Pressure—High: ≤ ~~[1102]~~ 1143 psig. 2 8 | ~~[18]~~ months 2 |
| SR 3.3.4.2.~~5~~ 4 6 | Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation. | ~~[18]~~ 24 months 2 |

1C

SURVEILLANCE REQUIREMENTS

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

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

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

25

-----------------------------------------------------------------------------

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.3.5.1.1 | Perform CHANNEL CHECK. | 12 hours |
| SR 3.3.5.1.2 | Perform CHANNEL FUNCTIONAL TEST. | [92] days 2 |
| 6 SR 3.3.5.1.3 | Calibrate the trip unit. | [92] days |
| 2 SR 3.3.5.1.4 3 6 | Perform CHANNEL CALIBRATION. | 92 days |
| SR 3.3.5.1.5 4 6 | Perform CHANNEL CALIBRATION. | [18] months 2 |
| SR 3.3.5.1.6 | Perform LOGIC SYSTEM FUNCTIONAL TEST. | [18] months 24 2 |
| SR 3.3.5.1.7 | Verify the ECCS RESPONSE TIME is within limits. | [18] 24 2 months on a STAGGERED TEST BASIS |
| SR 3.3.5.1.5 | Perform CHANNEL CALIBRATION | 24 months 24 |

B

C

B

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER FUNCTION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 1. Low Pressure Coolant Injection-A (LPCI) and Low Pressure Core Spray (LPCS) Subsystems | | | | | |
| a. Reactor Vessel Water Level — Low Low Low, Level 1 | 1,2,3, 4(a),5(a) | ~~2~~(b) 2 | B | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~ 6<br>SR 3.3.5.1.~~5~~ 4 6<br>SR 3.3.5.1.6<br>2 ~~SR 3.3.5.1.7~~ | ≥ ~~[-152.5]~~ -148 2 inches |
| b. Drywell Pressure — High | 1,2,3 | ~~2~~(b) | B | 12 ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>6 ~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4 6<br>SR 3.3.5.1.6<br>2 ~~SR 3.3.5.1.7~~ | ≤ ~~[1.44]~~ 1.88 2 psig |
| 24 INSERT 1.c AND 1.d<br>~~c.~~ e. LPCI Pump A Start — Time Delay Relay LOCA/LOOP 8 | 1,2,3, 4(a),5(a) | ~~1~~ 2 | C | SR 3.3.5.1.2<br>~~SR 3.3.5.1.4~~ 3<br>SR 3.3.5.1.6 | ≥ ~~[ ]~~ 3.04 2 seconds and ≤ ~~[ ]~~ 6.00 seconds |
| 24 ~~d.~~ f. Reactor ~~Steam~~ Vessel ~~Dome~~ Pressure — Low (Injection Permissive) | 1,2,3 | ~~3~~ 1 per valve | C | 12 ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>6 ~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4 6<br>SR 3.3.5.1.6<br>9 ~~SR 3.3.5.1.7~~ | ≥ ~~[ ]~~ 448 psig and ≤ ~~[ ]~~ 492 psig 2 |
| | 4(a),5(a) | ~~3~~ 2 | B | 12 ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>6 ~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4 6<br>SR 3.3.5.1.6<br>9 ~~SR 3.3.5.1.7~~ | ≥ ~~[ ]~~ 448 psig and ≤ ~~[ ]~~ 492 psig 2 |
| 9 24 ~~e.~~ g. ~~LPCS~~ Pump Discharge Flow — Low ~~(Bypass)~~ (Minimum Flow) 8 | 1,2,3, 4(a),5(a) | ~~1~~ | E | 12 ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>6 ~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4 6<br>SR 3.3.5.1.6 | ≥ ~~[ ]~~ 668 gpm and ≤ ~~[ ]~~ 1067 gpm 2 |
| h ~~f.~~ ~~LPCI~~ Pump A Discharge Flow — Low ~~(Bypass)~~ (Minimum Flow) | 1,2,3, 4(a),5(a) | ~~1~~ 2 | E | 12 ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>6 ~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4<br>SR 3.3.5.1.6 | ≥ ~~[ ]~~ 605 gpm and ≤ ~~[ ]~~ 784 gpm |
| i 24 ~~g.~~ Manual Initiation 2 | 1,2,3, 4(a),5(a) | ~~1~~ 2 | C | SR 3.3.5.1.~~6~~ 5 6 | NA 2 |

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated ~~Technical Specifications (TS) required functions~~ diesel generator (DG). 2

1B
1C
1B
1C
1B
1B
1B
1B
1B

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER FUNCTION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 2. LPCI B and LPCI C Subsystems | | | | | |
| a. Reactor Vessel Water Level — Low Low Low, Level 1 | 1,2,3, 4(a),5(a) | ~~2~~(b) 2 | B | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6<br>SR 3.3.5.1.7 | ≥ ~~[illegible]~~ -148 inches |
| b. Drywell Pressure — High | 1,2,3 | ~~2~~(b) | B | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6<br>SR 3.3.5.1.7 | ≤ ~~[illegible]~~ 1.88 psig |
| INSERT 2.c AND 2.d<br>e. LPCI Pump B LOCA/LOOP Start — Time Delay Relay | 1,2,3, 4(a),5(a) | ~~1~~ 2 | C | SR 3.3.5.1.2<br>SR 3.3.5.1.5<br>SR 3.3.5.1.6 | ≥ ~~[illegible]~~ 3.04 seconds and ≤ ~~[illegible]~~ 6.00 seconds |
| f. Reactor Vessel ~~Steam Dome~~ Pressure — Low (Injection Permissive) | 1,2,3 | ~~3~~ 1 per valve | C | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6<br>~~SR 3.3.5.1.7~~ | ≥ ~~[illegible]~~ 498 psig and ≤ ~~[illegible]~~ 492 psig |
| | 4(a),5(a) | ~~3~~ 2 | B | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6<br>~~SR 3.3.5.1.7~~ | ≥ ~~[illegible]~~ psig and ≤ ~~[illegible]~~ 492 psig |
| g. ~~LPCI~~ Pump B ~~and LPCI Pump C~~ Discharge Flow — Low (Minimum Flow) ~~(Bypass)~~ | 1,2,3, 4(a),5(a) | ~~2~~ ~~1 per pump~~ | E | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6 | ≥ ~~[illegible]~~ 605 gpm and ≤ ~~[illegible]~~ 984 gpm |
| ~~f. Manual Initiation~~ | 1,2,3, 4(a),5(a) | ~~1~~ 2 | C | SR 3.3.5.1.6 | NA |

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated ~~LS required functions~~ DG.

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER FUNCTION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 3. High Pressure Core Spray (HPCS) System | | | | | |
| a. Reactor Vessel Water Level — Low Low, Level 2 | 1,2,3, 4(a),5(a) | ~~[4]~~ 4(b) 2 | B | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4 6<br>SR 3.3.5.1.6<br>SR 3.3.5.1.7 | ≥ ~~[-43.8]~~ -58 inches 2 |
| b. Drywell Pressure — High | 1,2,3 | ~~[4]~~ 4(b) | B | 12 ~~[SR 3.3.5.1.1]~~<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~ 4 6<br>SR 3.3.5.1.5<br>SR 3.3.5.1.6<br>SR 3.3.5.1.7 | ≤ ~~[1.44]~~ 1.88 psig 2 |
| c. Reactor Vessel Water Level — High, Level 8 | 1,2,3, 4(a),5(a) | ~~[2]~~ 2 | C | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~ 4 6<br>SR 3.3.5.1.5<br>SR 3.3.5.1.6 | ≤ ~~[55.7]~~ 56 inches |
| d. Condensate Storage Tank Level — Low | 1,2,3, 4(c),5(c) | ~~[2]~~ | D | 12 ~~[SR 3.3.5.1.1]~~<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4 6<br>SR 3.3.5.1.6 | ≥ ~~[73] inches~~ 448 ft. 1 inch elevation 2 |
| e. Suppression Pool Water Level — High | 1,2,3 | ~~[2]~~ | D | 12 ~~[SR 3.3.5.1.1]~~<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4 6<br>SR 3.3.5.1.6 | ≤ ~~[7.0] inches~~ 466 ft 11 inches elevation |
| ~~f. [HPCS Pump Discharge Pressure — High (Bypass)]~~ | ~~1,2,3, 4(a),5(a)~~ | ~~[1]~~ | ~~E~~ | ~~SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>[SR 3.3.5.1.3]<br>SR 3.3.5.1.5<br>SR 3.3.5.1.6~~ | ~~≥ [ ] psig~~ |
| 25 f ~~g~~. ~~[~~HPCS System Flow Rate — Low ~~(Bypass)]~~ Minimum Flow 8 | 1,2,3, 4(a),5(a) | ~~[1]~~ 2 | E | 12 ~~[SR 3.3.5.1.1]~~<br>SR 3.3.5.1.2<br>6 ~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4 6<br>SR 3.3.5.1.6 | ≥ ~~[x]~~ 1200 gpm and ≤ ~~[y]~~ 1512 gpm 2 |
| 9 ~~h~~. Manual Initiation 2 | 1,2,3, 4(a),5(a) | ~~[1]~~ 2 | C | SR 3.3.5.1.6 | NA |

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated ~~[S required functions]~~ DG 2

(c) When HPCS is OPERABLE for compliance with LCO 3.5.2, "ECCS — Shutdown," and aligned to the condensate storage tank while tank water level is not within the limit of SR 3.5.2.2.

10 ~~B~~ 1 ~~B~~ 10 1 ~~B~~ 1 ~~B~~ 1 ~~B~~ 1 ~~B~~ 1 ~~B~~ 1 ~~B~~

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER FUNCTION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 4. Automatic Depressurization System (ADS) Trip System A | | | | | |
| a. Reactor Vessel Water Level — Low Low Low, Level 1 | 1,2$^{(d)}$,3$^{(d)}$ | ~~2~~ 2 | F | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4<br>SR 3.3.5.1.6 | ≥ ~~[-152.5]~~ -148 inches |
| ~~b. Drywell Pressure — High~~ | ~~1,2$^{(d)}$,3$^{(d)}$~~ | ~~[2]~~ | ~~F~~ | ~~SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>[SR 3.3.5.1.3]<br>SR 3.3.5.1.5<br>SR 3.3.5.1.6~~ | ~~≤ [1.44] psig~~ |
| ~~c.~~ b. ADS Initiation Timer | 1,2$^{(d)}$,3$^{(d)}$ | ~~1~~ | G | SR 3.3.5.1.2<br>[SR 3.3.5.1.~~4~~ 3<br>SR 3.3.5.1.6 | ≤ ~~[117]~~ 115.0 seconds |
| ~~d.~~ c. Reactor Vessel Water Level — Low, Level 3 ~~(Confirmatory)~~ Permissive | 1,2$^{(d)}$,3$^{(d)}$ | ~~1~~ 2 | F | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.~~5~~ 4<br>SR 3.3.5.1.6 | ≥ ~~[10.8]~~ 9.5 inches |
| ~~e.~~ d. LPCS Pump Discharge Pressure — High | 1,2$^{(d)}$,3$^{(d)}$ | ~~2~~ | G | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4<br>SR 3.3.5.1.6 | ≥ ~~[125]~~ 119 psig and ≤ ~~[165]~~ 171 psig |
| ~~f.~~ e. LPCI Pump A Discharge Pressure — High | 1,2$^{(d)}$,3$^{(d)}$ | ~~2~~ 2 | G | ~~SR 3.3.5.1.1~~<br>SR 3.3.5.1.2<br>~~SR 3.3.5.1.3~~<br>SR 3.3.5.1.~~5~~ 4<br>SR 3.3.5.1.6 | ≥ ~~[115]~~ 116 psig and ≤ ~~[135]~~ 134 psig |
| ~~g. [ADS Bypass Timer (High Drywell Pressure)]~~ | ~~1,2$^{(d)}$,3$^{(d)}$~~ | ~~[2]~~ | ~~G~~ | ~~SR 3.3.5.1.2<br>[SR 3.3.5.1.4]<br>SR 3.3.5.1.6~~ | ~~≤ [9.4] minutes~~ |
| ~~h.~~ g. Manual Initiation | 1,2$^{(d)}$,3$^{(d)}$ | ~~2~~ 4 | G | SR 3.3.5.1.6 | NA |
| f. Accumulator Backup Compressed Gas System Pressure - Low | 1,2$^{(d)}$,3$^{(d)}$ | 3 | F | SR 3.3.5.1.2<br>SR 3.3.5.1.4<br>SR 3.3.5.1.6 | ≥ 151.4 psig |

(continued)

(d) With reactor steam dome pressure > ~~150~~ psig.

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER FUNCTION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 5. ADS Trip System B | | | | | |
| a. Reactor Vessel Water Level — Low Low Low, Level 1 | 1,2$^{(d)}$,3$^{(d)}$ | ~~[2]~~ 2 | F | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6 | ≥ ~~[-152.5]~~ -148 inches |
| ~~b. Drywell Pressure — High~~ | ~~1,2$^{(d)}$,3$^{(d)}$~~ | ~~[2]~~ | ~~F~~ | ~~SR 3.3.5.1.1~~<br>~~SR 3.3.5.1.2~~<br>~~[SR 3.3.5.1.3]~~<br>~~SR 3.3.5.1.5~~<br>~~SR 3.3.5.1.6~~ | ~~≤ [1.44] psig~~ |
| b c. ADS Initiation Timer | 1,2$^{(d)}$,3$^{(d)}$ | ~~[1]~~ 2 | G | SR 3.3.5.1.2<br>~~[SR 3.3.5.1.5]~~ 4<br>SR 3.3.5.1.6 | ≤ ~~[117]~~ 115.9 seconds |
| c d. Reactor Vessel Water Level — Low, Level 3 ~~(Confirmatory)~~ Permissive | 1,2$^{(d)}$,3$^{(d)}$ | ~~[1]~~ 2 | F | SR 3.3.5.1.1<br>SR 3.3.5.1.2<br>~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6 | ≥ ~~[10.8]~~ 9.5 inches |
| d e. LPCI Pumps B & C Discharge Pressure — High | 1,2$^{(d)}$,3$^{(d)}$ | 4 ~~[2 per pump]~~ | G | ~~[SR 3.3.5.1.1]~~<br>SR 3.3.5.1.2<br>~~[SR 3.3.5.1.3]~~<br>SR 3.3.5.1.5 4<br>SR 3.3.5.1.6 | ≥ ~~[125]~~ 116 psig and ≤ ~~[135]~~ 134 psig |
| ~~f. [ADS Bypass Timer (High Drywell Pressure)]~~ | ~~1,2$^{(d)}$,3$^{(d)}$~~ | ~~[2]~~ | ~~G~~ | ~~SR 3.3.5.1.2~~<br>~~[SR 3.3.5.1.4]~~<br>~~SR 3.3.5.1.6~~ | ~~≤ [9.4] minutes~~ |
| e. Accumulator Backup Compressed Gas System Pressure — Low | 1,2$^{(d)}$,3$^{(d)}$ | 3 | F | SR 3.3.5.1.2<br>SR 3.3.5.1.4<br>SR 3.3.5.1.6 | ≥ 151.4 psig |
| ~~g.~~ f. Manual Initiation | 1,2$^{(d)}$,3$^{(d)}$ | ~~[2]~~ 4 | G | SR 3.3.5.1.6 | NA |

(d) With reactor steam dome pressure > ~~[150]~~ psig.

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.3.6.1.7 | (2) ~~NOTE~~ ~~Radiation detectors may be excluded.~~<br><br>Verify the ISOLATION SYSTEM RESPONSE TIME is within limits.<br><br>~~Reviewer's Note: This SR is applied only to Functions of Table 3.3.6.1-1 with required response times not corresponding to DG start time.~~ (31) | ~~18~~ (24) months on a STAGGERED TEST BASIS (2) |

| | | | | | |
|---|---|---|---|---|---|
| c. Blowdown Flow—High | 1,2,3 | 1 | F | SR 3.3.6.1.1<br>SR 3.3.6.1.2<br>SR 3.3.6.1.5<br>SR 3.3.6.1.6<br>SR 3.3.6.1.7 | ≤ 271.7 gpm |

1C

32

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

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER TRIP SYSTEM | CONDITIONS REFERENCED FROM REQUIRED ACTION C.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 4. RWCU System Isolation (continued) | | | | | |
| e. ~~c.~~ ~~RWCU~~ Heat Exchanger ~~Equipment~~ Area Room Temperature-High | 1,2,3 | ~~[1]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6 | ≤ ~~[126]~~ 160 °F |
| ~~d.~~ e. ~~RWCU~~ Heat Exchanger ~~Equipment~~ Area Ventilation Room Differential Temperature – High | 1,2,3 | ~~[1]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6 | ≤ ~~[68]~~ 70 °F |
| f ~~e.~~ ~~RWCU~~ Pump ~~Rooms~~ Area Temperature – High | 1,2,3 | ~~[2]~~ ~~[1 per room]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6 | ≤ ~~[176]~~ 180 °F |
| g ~~f.~~ ~~RWCU~~ Pump ~~Rooms~~ Area Ventilation Differential Temperature – High | 1,2,3 | ~~[2]~~ ~~[1 per room]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6 | ≤ ~~[38]~~ 100 °F |
| h ~~g.~~ RWCU ~~Valve Nest Room~~ RCIC Line Routing Area Temperature – High | 1,2,3 | ~~[1]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6 | ≤ ~~[141]~~ 180 °F |
| i ~~h.~~ RWCU ~~Valve Nest Room~~ Line Routing Area ~~Differential~~ Temperature – High | 1,2,3 | ~~[1]~~ 1 per room | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2 3<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 | ~~≤ [63] °F~~ |
| ~~i. Main Steam Line Tunnel Ambient Temperature – High~~ | ~~1,2,3~~ | ~~[1]~~ | ~~F~~ | ~~SR 3.3.6.1.1~~<br>~~SR 3.3.6.1.2~~<br>~~SR 3.3.6.1.5~~<br>~~SR 3.3.6.1.6~~ | ~~≤ [191] °F~~ |
| ~~j. Main Steam Line Tunnel Differential Temperature – High~~ | ~~1,2,3~~ | ~~[1]~~ | ~~F~~ | ~~SR 3.3.6.1.1~~<br>~~SR 3.3.6.1.2~~<br>~~SR 3.3.6.1.5~~<br>~~SR 3.3.6.1.6~~ | ~~≤ [104] °F~~ |
| j ~~k.~~ Reactor Vessel Water Level – Low Low, Level 2 | 1,2,3 | ~~[2]~~ 2 | F | ~~SR 3.3.6.1.1~~ 12<br>SR 3.3.6.1.2<br>~~SR 3.3.6.1.3~~ 6<br>SR 3.3.6.1.5 4<br>SR 3.3.6.1.6 6<br>~~SR 3.3.6.1.7~~ 31 | ≥ ~~[-43.8]~~ -58 inches |
| k ~~l.~~ ~~Standby Liquid Control~~ SLC System Initiation | 1,2 | ~~[2]~~ 2(c) | I | SR 3.3.6.1.6 | NA |
| ~~m. Manual Initiation~~ | ~~1,2,3~~ | ~~[2]~~ | ~~G~~ | ~~SR 3.3.6.1.6~~ | ~~NA~~ |

(continued)

| | |
|---|---|
| Room 409, 509 Areas | ≤ 175 °F |
| Room 408, 511 Areas | ≤ 180 °F |

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

Control Room Emergency Filtration 2

Table 3.3.7.1-1 (page 1 of 1)
~~Control Room Fresh Air~~ System Instrumentation

| FUNCTION | APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS | REQUIRED CHANNELS PER TRIP SYSTEM | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|---|
| 1. Reactor Vessel Water Level — Low Low, Level 2 | 1,2,3, ~~(a)~~ | ~~2~~ | B | SR 3.3.7.1.1<br>SR 3.3.7.1.2<br>~~SR 3.3.7.1.3~~<br>SR 3.3.7.1.4 3<br>SR 3.3.7.1.5 4 | ≥ ~~-43.8~~ -58 inches |
| 2. Drywell Pressure — High | 1,2,3 | ~~2~~ | C | SR 3.3.7.1.1<br>SR 3.3.7.1.2<br>~~SR 3.3.7.1.3~~<br>SR 3.3.7.1.4 3<br>SR 3.3.7.1.5 4 | ≤ ~~1.43~~ 1.88 psig |
| ~~3.~~ 4. Control Room Ventilation Radiation Monitors Main | 1,2,3, (a),(b) | ~~2~~ per intake | ~~D~~ E | SR 3.3.7.1.1<br>SR 3.3.7.1.2<br>SR 3.3.7.1.4 3<br>~~SR 3.3.7.1.5~~ | ≤ ~~[5] mR/hr~~ 3800 cpm |
| 3. Reactor Building Vent Exhaust Plenum Radiation - High | 1,2,3, (a),(b) | 2 | B | SR 3.3.7.1.1<br>SR 3.3.7.1.2<br>SR 3.3.7.1.3<br>SR 3.3.7.1.4 | ≤16.0 mR/hr |

(a) During operations with a potential for draining the reactor vessel.

(b) During ~~CORE ALTERATIONS, and during~~ movement of irradiated fuel assemblies in the ~~primary or~~ secondary containment.

1C

## 3.3 INSTRUMENTATION

### 3.3.8.1 Loss of Power (LOP) Instrumentation

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

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS

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

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| ~~A.~~ C 46 As required by Required Action A.1 and referenced in Table 3.3.8.1-1. ~~One or more channels inoperable.~~ | ~~A.1~~ C.1 46 Place channel in trip. | 1 hour |
| ~~B.~~ D 46 Required Action and associated Completion Time of Condition B or C not met. | ~~B.1~~ D.1 46 Declare associated DG inoperable. | Immediately |

Insert ACTIONS A and B 46

<Insert ACTION D> 41

C

C

C

46

## INSERT ACTIONS A AND B

| | | |
|---|---|---|
| A. One or more required channels inoperable. | A.1 Enter the Condition referenced in Table 3.3.8.1-1 for the channel. | Immediately |
| B. As required by Required Action A.1 and referenced in Table 3.3.8.1-1. | B.1 Declare associated DG inoperable. | 1 hour from discovery of loss of initiation capability for the associated DG |
| | AND | |
| | B.2 Restore channel to OPERABLE status. | 24 hours |

C

41

## INSERT ACTION D

1C

| | | |
|---|---|---|
| | OR | |
| | ------------NOTE------------<br>Only applicable for Functions 1.c and 1.d.<br>---------------------------- | |
| | D.2.1 Open offsite circuit supply breaker to associated 4.16 kV ESF bus. | Immediately |
| | AND | |
| | D.2.2 Declare associated offsite circuit inoperable. | Immediately |

1C

1C

Insert Page 3.3-80

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

CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 (46)

| FUNCTION | REQUIRED CHANNELS PER DIVISION | CONDITIONS REFERENCED FROM REQUIRED ACTION A.1 | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|---|
| 1. Divisions 1 and 2 – 4.16 kV Emergency Bus Undervoltage (41) | | | | |
| a. TR-S Loss of Voltage – 4.16 kV Basis (13) | ~~[4]~~ 1 (2) | B | ~~SR 3.3.8.1.1~~ (12)<br>~~SR 3.3.8.1.2~~ (40)<br>SR 3.3.8.1.3 (2) (12)<br>SR 3.3.8.1.4 | ≥ [illegible] 2450 V and ≤ [illegible] 3135 V (2) |
| b. Loss of Voltage – Time Delay | ~~[4]~~ | B | ~~SR 3.3.8.1.2~~<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ [illegible] 2.95 seconds and ≤ [illegible] 7.1 seconds (2) |
| e. Degraded Voltage – 4.16 kV Basis (13) (41) | (2) [4] 2(a) | C | ~~SR 3.3.8.1.1~~ (12)<br>SR 3.3.8.1.2 (1)<br>SR 3.3.8.1.3 (2)<br>SR 3.3.8.1.4 | ≥ [illegible] 3685 V and ≤ [illegible] 3755 V (2) |
| f. Degraded Voltage – Primary Time Delay (8) | [4] | C | SR 3.3.8.1.2 (1) (12)<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 (2) (12) | ≥ [illegible] 5.0 seconds and ≤ [illegible] 5.3 seconds (2) |
| 2. Division 3 – 4.16 kV Emergency Bus Undervoltage | | | | |
| a. Loss of Voltage – 4.16 kV Basis (13) | [4] (2) | B | ~~SR 3.3.8.1.1~~ (12)<br>~~SR 3.3.8.1.2~~ (40)<br>SR 3.3.8.1.3 (2) (12)<br>SR 3.3.8.1.4 | ≥ [illegible] 2450 V and ≤ [illegible] 3135 V |
| b. Loss of Voltage – Time Delay | [4] (2) | B | ~~SR 3.3.8.1.2~~<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ [illegible] 1.87 seconds and ≤ [illegible] 3.73 seconds (2) |
| c. Degraded Voltage – 4.16 kV Basis (13) | [4] (2) | C | ~~SR 3.3.8.1.1~~ (12)<br>~~SR 3.3.8.1.2~~ (40)<br>SR 3.3.8.1.3 (2) (12)<br>SR 3.3.8.1.4 | ≥ [illegible] 3685 V and ≤ [illegible] 3755 V |
| d. Degraded Voltage – Time Delay, ~~No LOCA~~ (41) | [4] | C | ~~SR 3.3.8.1.2~~ (2)<br>SR 3.3.8.1.3 (2)<br>SR 3.3.8.1.4 | ≥ [illegible] 7.36 ~~minutes~~ seconds and ≤ [illegible] 8.34 ~~minutes~~ seconds (2) |
| ~~e. Degraded Voltage – Time Delay, LOCA~~ | ~~(4)~~ | | ~~SR 3.3.8.1.2~~<br>~~SR 3.3.8.1.3~~<br>~~SR 3.3.8.1.4~~ | ~~≥ [3.6] seconds and ≤ 4.4 seconds~~ |

(41)

(a) The Degraded Voltage – 4.16 kV Basis and – Primary Time Delay Functions must be associated with one another.



(41)

| | | | | |
|---|---|---|---|---|
| g. Degraded Voltage – Secondary Time Delay | 1 | C | SR 3.3.8.1.2<br>SR 3.3.8.1.3 | ≥ 2.63 seconds and ≤ 3.39 seconds |
| c. TR-B Loss of Voltage – 4.16 kV Basis | 1 | C | SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 2450 V and ≤ 3135 V (41) |
| d. TR-B Loss of Voltage – Time Delay | 1 | C | SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 3.06 seconds and ≤ 9.28 seconds |

C
B
B
B
B
C
B
B
B
B
C
C
B
C

## 3.3 INSTRUMENTATION

### 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS electric power monitoring assemblies shall be OPERABLE for each inservice RPS motor generator set or alternate power supply.

43 that supports equipment required to be OPERABLE,

2 with both residual heat removal (RHR) shutdown cooling (SDC) suction isolation valves open, 1C 1B 1A

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

44 MODE 5

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| 43 required<br>A. One or both inservice power supplies with one electric power monitoring assembly inoperable. | A.1 Remove associated inservice power supply(s) from service. | 72 hours |
| 43 required<br>B. One or both inservice power supplies with both electric power monitoring assemblies inoperable. | B.1 Remove associated inservice power supply(s) from service. | 1 hour |
| C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3. | C.1 Be in MODE 3.<br>AND<br>C.2 Be in MODE 4. | 12 hours<br><br>36 hours |

1B 1B

(continued)

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.3.8.2.2 | Perform CHANNEL CALIBRATION. The Allowable Values shall be:<br><br>2<br><br>a. Overvoltage, with time delay ≤ 3.46 seconds;<br>Bus A ≤ ~~[132.9]~~ 133.8 V<br>~~Bus B ≤ [133.0] V~~<br><br>b. Undervoltage, with time delay ≤ 3.46 seconds; and<br>Bus A ≥ ~~[112.0]~~ 110.8 V<br>~~Bus B ≥ [115.9] V~~<br><br>c. Underfrequency, with time delay ~~set to [zero]~~<br>Bus A ≥ [57] Hz<br>~~Bus B ≥ [57] Hz~~<br>≤ 3.46 seconds. 2 | ~~[~~18~~]~~ months<br>2 |
| SR 3.3.8.2.3 | Perform a system functional test. | ~~[~~18~~]~~ months 2 |

1. Not used. 1C

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

3. The WNP-2 design does not include a direct scram on high reactor vessel water level. Therefore, this Function and associated ACTIONS and Surveillances have been deleted. The following requirements have been renumbered, where applicable, to reflect this deletion.

4. The Frequency for performing proposed SR 3.3.1.1.3 has been extended from 7 days to 92 days. Since this new Frequency is now the same as the current 92 day CHANNEL FUNCTIONAL TEST (CFT) Frequency for the APRM Flow Biased Simulated Thermal Power—High Function, this specific Surveillance has been incorporated into the 92 day CFT Surveillance. Current WNP-2 requirements test this feature as part of a CFT in addition to its normally required 7 day Surveillance Frequency. For further technical discussion of this change, refer to Comment L.9 of the Discussion of Changes for ITS 3.3.1.1. In addition, the following requirements have been renumbered, where applicable, to reflect this deletion.

5. The Frequency for current SR 3.3.1.1.8 (proposed SR 3.3.1.1.7) has been changed from 1000 MWD/T to 1200 MWD/T, consistent with the current WNP-2 Licensing Basis (the current Frequency is 1000 EFPH, which is essentially 1200 MWD/T).

6. This bracketed Surveillance has been deleted since it is not applicable to WNP-2. The WNP-2 design does not include trip units except for the SDV transmitter/trip unit, which does not currently require this bracketed Surveillance. In addition, the following requirements have been renumbered, where applicable, to reflect this deletion.

7. The Surveillances have been placed in the proper order, based on decreasing Frequency, consistent with the Writer's Guide convention. The requirements have been renumbered, where applicable, to reflect their new order.

8. The proper WNP-2 plant specific nomenclature/value/design requirements have been provided.

9. Not used. 1C

10. This bracketed requirement has been deleted since it is not applicable to WNP-2. The current WNP-2 Licensing Basis does not require the Allowable Value to be reset during single loop operations.

11. The RPS Response Time Surveillance Requirement for this Function has been deleted since current WNP-2 Licensing Basis does not include a response time other than the time constant, which is already covered by current NUREG SR 3.3.1.1.14 (proposed SR 3.3.1.1.11).

12. The CHANNEL CHECK Surveillance Requirement for: a) the Reactor Vessel Steam Dome Pressure—High, Primary Containment Pressure—High, and SDV Water Level—High RPS Functions; b) the Reactor Vessel Steam Dome Pressure—High ATWS-RPT Function; c) the Drywell Pressure—High, Reactor Vessel Pressure—Low, LPCS Pump Discharge Flow—Low (Minimum Flow), LPCI Pumps A, B, and C Discharge Flow—Low (Minimum Flow), Condensate Storage Tank Level—Low, Suppression Pool Water Level—High, HPCS System Flow Rate—Low (Minimum Flow), LPCS Pump Discharge Pressure—High, and LPCI Pumps A, B, and C Discharge Pressure—High ECCS Functions; d) the Main Steam Line Reactor Vessel Water Level—Low Low, Level 2, Main Steam Line Pressure—Low, Main Steam Line Condenser Vacuum—Low, Main Steam Tunnel Temperature—High, Main Steam Tunnel Differential Temperature—High, Primary Containment Reactor Vessel Water Level—Low Low, Level 2, Drywell Pressure—High, RCIC Steam Supply Pressure—Low, RCIC Turbine Exhaust Diaphragm Pressure—High, RCIC Equipment Room Area Temperature—High, RCIC Equipment Room Area Differential Temperature—High, RWCU Heat Exchanger Room Area Temperature—High, RWCU Heat Exchanger Room Area Ventilation Differential Temperature—High, RWCU Pump Room Area Temperature—High, RWCU/RCIC Line Routing Area Temperature—High, RWCU Line Routing Area Temperature—High, RWCU Reactor Vessel Water Level—Low Low, Level 2, RHR Pump Room Area Temperature—High, RHR Pump Room Area Ventilation Differential Temperature—High, and RHR Reactor Vessel Pressure—High Isolation Functions; e) Secondary Containment Reactor Vessel Water Level—Low Low, Level 2, and Drywell Pressure—High Isolation Functions; and f) the Loss of Power Instrumentation Functions, has been deleted since the current WNP-2 design does not include indication to perform a CHANNEL CHECK. The following Surveillances have been renumbered, where applicable, to reflect this deletion.

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

14. The BWR/6 LCO 3.3.2.1 has been deleted and, in its place, the BWR/4 LCO 3.3.2.1 (from NUREG-1433) has been used since the WNP-2 design is similar to the BWR/4 design with regards to the control rod block instrumentation. Any deviations from the BWR/4 ITS are discussed.

15. A new Specification has been added, proposed LCO 3.3.2.2. This Specification is from the BWR/4 ITS (NUREG-1433), since the WNP-2 design is similar to the BWR/4 design with regards to the feedwater and main turbine high water level trip instrumentation. Therefore, the BWR/4 LCO is used and any deviations from the BWR/4 ITS are discussed.

16. SR 3.3.2.1.4 and Table 3.3.2.1-1, Note (a) have been modified and Table 3.3.2.1-1, Functions 1.b, 1.c, and 1.f and Notes (b), (c), (d), and (e) have been deleted to be consistent with the WNP-2 RBM design. The RBM design in the ITS is based on a "post-ARTS" RBM design. WNP-2 has not installed the "ARTS" modification. In addition, the requirements have been renumbered, where applicable, to reflect the deletions.

17. The proper Specification number has been provided.

18. ACTION D and the Note in Condition C has been deleted. These current requirements specify a 72 hour Completion Time to restore one hydrogen monitor to OPERABLE status when two hydrogen monitors are inoperable. This change will allow a 7 day Completion Time to restore one hydrogen monitor when both are inoperable, as shown in ACTION C. There is no difference, with respect to their importance during an accident, between the $H_2$ and $O_2$ monitors and other PAM instrumentation. The $H_2$ and $O_2$ monitors are located outside the primary containment, similar to most other PAM Functions. The function of the $H_2$ and $O_2$ monitors is to determine $H_2$ and $O_2$ concentrations to ensure the $H_2$ recombiners are operated in sufficient time following an accident to limit $H_2$ and $O_2$ concentrations below the flammability limits. If the $H_2$ and $O_2$ monitors are inoperable, the $H_2$ recombiners can be operated immediately following an accident; there is no negative effect of turning on the $H_2$ recombiners too soon following an accident. The Post Accident Sampling System (PASS), which is independent to the monitors, can be used to sample the primary containment to determine $H_2$ and $O_2$ concentrations. The monitors can also be used to determine an approximation of core damge during a severe accident. However, the PASS would normally be used during a severe accident to determine the amount of fuel damage (the monitors are simply a backup to the PASS, and do not provide as detailed information as the PASS does). In addition, the requirements have been renumbered, where applicable, to reflect this deletion. B

19. Since there is one PAM Function that specifies more than two channels, Condition C and Required Action C.1 has been modified to reflect this requirement.

20. A Note has been added to the Surveillance Requirements (Note 2 for LCO 3.3.3.1, the Note for LCO 3.3.3.2, and the Note for LCO 3.3.8.2) to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances provided the other channel(s) in the associated Function are 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). The NRC has also granted this allowance in other topical reports for the RPS, ECCS, and isolation instrumentation. In addition, the current Note to the Surveillance Requirements for LCO 3.3.3.1 has been numbered "1" to reflect this addition.

21. This Reviewer's Note has been deleted and the appropriate instruments have been added to the Table, consistent with the Note. The Note is not meant to be retained in the final version of the plant specific submittal. In addition, the Functions have been renumbered, where applicable, to reflect the additions and deletions.

22. The Remote Shutdown System Table (Table 3.3.3.2-1) has been relocated to other plant controlled documents (the Licensee Controlled Specifications Manual). this change is consistent with the provisions of Generic Letter 91-08 for the removal of lists and has been recently approved for Clinton Power Station (amendment 68) on that basis.

23. The design of the EOC-RPT System and the applicable safety analysis is such that EOC-RPT is assumed at all times when THERMAL POWER is ≥ 30% RTP, not just when the recirculation pumps are in fast speed. Therefore, the Applicability has been modified to reflect this design and analysis assumption. In addition, Required Action C.1 has also been modified to delete the reference to the fast speed breaker.

24. Six new ECCS Functions have been added. Functions 1.c, 1.d, 2.c, and 2.d are time delay relays that delay starting of the low pressure ECCS pumps following a LOCA with offsite power available. These Functions are similar to those Functions in the NUREG that delay starting ECCS pumps following a LOCA with offsite power not available (current Functions 1.c and 2.c, proposed Functions 1.e and 2.e). Functions 4.f and 5.e are ADS Accumulator Backup Compressed Gas System Pressure—Low Functions that automatically align a safety-related air supply to the ADS valves. Appropriate ACTIONS and SRs have also been added. In addition, the Functions and SRs have been renumbered, where applicable, to reflect these additions. B

25. The current WNP-2 design does not include the HPCS Pump Discharge Pressure—High (Bypass), ADS Drywell Pressure—High, and ADS Bypass Timer (High Drywell Pressure) Functions (current NUREG Functions 3.f, 4.b, 4.g, 5.b, and 5.f). Therefore, these Functions have been deleted and the remaining Functions have been renumbered, where applicable, to reflect these deletions.

26. Not used. C

27. The current WNP-2 design does not include the RCIC Suppression Pool Water Level—High Function (current NUREG Function 4). Therefore, this Function has been deleted and the remaining Function has been renumbered to reflect this deletion.

28. The proper Primary Containment Isolation Functions that are common to the RPS Instrumentation have been provided.

29. The Reactor Building Exhaust Plenum Radiation—High Function (proposed Function 2.d, current NUREG Function 2.g) is not currently required nor needed in MODES other than MODES 1, 2, and 3. Therefore, this requirement has been deleted. The associated ACTION (ACTION K) has also been deleted.

30. The proper CHANNEL CALIBRATION Frequency for the RWCU Differential Flow—Time Delay has been provided (24 months). Therefore, this Surveillance, which performs the CHANNEL CALIBRATION every 92 days, has been deleted.

31. This Reviewer's Note has been deleted and the appropriate Functions now include this SR requirement, consistent with the Note. The Note is not meant to be retained in the final version of the plant specific submittal. For the Secondary Containment Isolation Instrumentation Functions, there are no appropriate Functions. Therefore, the entire NUREG SR 3.3.6.2.6 has been deleted.

32. Six new Primary Containment Isolation Functions have been added (proposed Functions 2.a, 3.g, 4.b, 4.c, 5.c, and 5.f), consistent with current WNP-2 Licensing Basis. In addition, 14 Functions have been deleted (current NUREG Functions 2.c, 2.d, 2.e, 2.f, 3.g, 3.h, 3.i, 3.j, 3.k, 3.l, 3.m, 4.i, 4.j, and 5.e) since they are not applicable to WNP-2. The Functions have been renumbered, where applicable, to reflect these additions and deletions.

33. This Secondary Containment Isolation Instrumentation Function (current NUREG Function 4) has been deleted since it is not applicable to WNP-2. The following Function has been renumbered to reflect this deletion.

34. This Specification has been deleted since the WNP-2 RHR Drywell Spray System is manually actuated using the RHR System pump and valve controls.

35. This Specification has been deleted since the WNP-2 Suppression Pool Makeup is manually actuated.

36. The current WNP-2 Licensing Basis does not include Technical Specification requirements for the relief mode of the SRVs since the overpressure protection analysis does not assume the relief mode functions to mitigate an overpressurization event. The WNP-2 design does not include a LLS mode of the SRVs. Therefore, this Specification has been deleted.

37. Proposed ACTIONS E and F have been added (and current NUREG ACTION D deleted) to provide the proper requirements for the Main Control Room Ventilation radiation Monitor. This monitor does not provide an automatic start of the CREF System or isolation of the control room; it provides an alarm only to alert the operators to a high radiation condition at the remote air intakes. These ACTIONS are consistent with the current WNP-2 Licensing Basis, as modified by the changes annotated in the Discussion of Changes for ITS 3.3.7.1. Refer to Comments M.4, L.2, and L.3 of the Discussion of Changes for ITS 3.3.7.1 for further discussion. The other ACTIONS have been renumbered, where applicable, to reflect this change. In addition, Note 2 to the Surveillance Requirements has been modified and the LSFT requirement has been deleted to reflect this design.

38. The WNP-2 design of the CREF System does not include a toxic gas mode; therefore, this Note has been deleted.

39. The CREF System Reactor Building Vent Exhaust Plenum Radiation—High Function has been added (proposed Function 3) consistent with current WNP-2 Licensing Basis. The other Functions have been renumbered, where applicable, to reflect this change.

40. The current WNP-2 Licensing Basis only requires the CHANNEL FUNCTIONAL TEST (CFT) to be performed every 18 months as part of the CHANNEL CALIBRATION. Therefore, a specific CFT Surveillance Requirement has been deleted.

41. The LOP Instrumentation Divisions 1 and 2 Degraded Voltage—Secondary Time Delay Function has been added (proposed Function 1.e) consistent with current design. The LOP Instrumentation Division 3 Degraded Voltage—Time Delay, LOCA Function has been deleted (current NUREG Function 2.e) since the WNP-2 design does not include separate non-LOCA and LOCA time delays. In addition, footnote (a) has been added consistent with the WNP-2 design. The LOP Instrumentation has also been modified by adding new Functions 1.c and 1.d. These Functions, placing requirements on the TR-B loss of voltage instrumentation, ensure that if TR-B (the alternate offsite circuit) is tied to the 4.16 kV ESF buses during a loss of voltage event, the associated breakers will be tripped to allow the DG to tie to the 4.16 kV ESF buses. These instruments are similar to the TR-S loss of voltage instrumentation currently in the WNP-2 TS. Appropriate ACTIONS and SRs have also been added. The SRs have been renumbered due to the addition. B

42. A new Note has been added to NUREG SR 3.3.1.2.5 to state that the determination of the signal to noise ratio is not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel in the associated core quadrant. When starting to load fuel from the defueled condition, SR 3.3.1.2.5 must be current prior to the start of fuel load. However, with no fuel in the core, a signal to noise ratio cannot be determined. Therefore, this Note has been added similar to the Note in the count rate Surveillance (SR 3.3.1.2.4), which is for the same reason as this proposed Note.

43. In MODES 4 and 5, the RPS Electric Power Monitoring assemblies (LCO 3.3.8.2) are required to support the instrumentation that provides an isolation signal to the RHR SDC suction isolation valves. The instrumentation is listed in LCO 3.3.6.1, and only one of the two trip systems is required when RHR SDC System integrity is maintained (ITS Note c to Table 3.3.6.1-1). This LCO requires two RPS Electric Power Monitoring assemblies to be OPERABLE for each inservice RPS power supply. However, only one RPS power supply is needed to support the required instrumentation, provided the RHR SDC System integrity is maintained. Currently, this LCO requires RPS Electric Power Monitoring assemblies to be OPERABLE on an inservice RPS power supply (which is normally maintained inservice at all times), even when no equipment is required to be OPERABLE. Therefore, the words "that support equipment required to be OPERABLE" have been added. This will allow the RPS Electric Power Monitoring assemblies on one of the two RPS power supplies to be inoperable when no required equipment is being powered from the associated RPS power supply. In addition, the word "required" has been added to Conditions A and B for consistency with the Writer's Guide, since, based on the above described change, all RPS Electric Power Monitoring assemblies may not be required OPERABLE at all times. B

44. The MODE 4 and 5 Applicability of LCO 3.3.8.2, "RPS Electric Power Monitoring," as it relates to control rod withdrawal, is revised to not include MODE 4, consistent with the Applicability of RPS Functions in LCO 3.3.1.1. In MODE 4, a control rod may be withdrawn from a core cell containing one or more fuel assemblies in accordance with LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown." Therefore, LCO 3.10.4 includes OPERABILITY requirements for RPS Functions and control rods (LCO 3.9.5). As a result, LCO 3.10.4 has been modified to also include requirements for the RPS Electric Power Monitoring assemblies to be OPERABLE when the RPS Functions and control rods are required to be OPERABLE (See Section 3.10, Justification for Deviations, comment 9). Commensurate changes to the ACTIONS of LCO 3.3.8.2 have also been made for consistency. The current ACTION D has been split into two separate ACTIONS, one for when the RHR SDC suction isolation valves are open and the other for when a control rod is withdrawn. This provides separate and discrete ACTIONS for the two separate Applicabilities (MODE 4 and 5 with both RHR SDC suction isolation valves open and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies). B

45. The ATWS-RPT System consists of two trip systems, with two channels of Reactor Vessel Steam Dome Pressure—High and two channels of Reactor Vessel Water Level—Low Low, Level 2 in each trip system. Each Function is a two-out-of-two logic; however, each trip system only trips one of the two recirculation pumps. Therefore, loss of one channel results in the loss of trip capability of one recirculation pump until the channel is either restored or placed in the trip condition. NUREG-1434 provides a 14 day Completion Time since it is assumed that both recirculation pumps can be tripped by the remaining trip system. Since the WNP-2 design does not provide the capability to trip both pumps with the remaining trip system, the Completion Time is shortened to 7 days.

46. The Loss of Voltage logic is a one-out-of-two design for each division, with both channels being required Operable. With one channel inoperable, the other channel is fully capable of performing the loss of voltage initiation function. Therefore, a 24 hour restoration time has been provided when one of the two channels in a division are inoperable (proposed Required Action B.2). When both channels for the division are inoperable, a 1 hour restoration time is provided (proposed Required Action B.1), consistent with NUREG-1434, Rev. 1. Due to this new ACTION for the Loss of Voltage channels, proposed ACTION A has been added which directs entry into Table 3.3.8.1-1 to determine the proper ACTION to take for an inoperable channel. This format is consistent with other Instrumentation Technical Specifications when different ACTIONS are necessary for the instrumentation Functions (e.g., ITS 3.3.5.1). Table 3.3.8.1-1 has been modified to direct entry into the proper Condition when a Function is inoperable. In addition, due to the addition of proposed ACTIONS A and B, the following ACTIONS have been renumbered. C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.2 Flow Control Valves (FCVs)

LCO 3.4.2 A recirculation loop FCV shall be OPERABLE in each operating recirculation loop.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or two required FCVs inoperable. | A.1 Lock up the FCV. | 4 hours |
| B. Required Action and associated Completion Time not met. | B.1 Be in MODE 3. | 12 hours |

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.2.1 | Verify each FCV fails "as is" on loss of hydraulic pressure at the hydraulic unit. | [18] months |

(continued)

A

17

SURVEILLANCE REQUIREMENTS (continued)

| | SURVEILLANCE | FREQUENCY |
|---|---|---|
| SR 3.4.2.2 | Verify average rate of each FCV movement is:<br>a. ≤ [11]% of stroke per second for opening; and<br>b. ≤ [11]% of stroke per second for closing. | [18] months |

17

C

C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.3 Jet Pumps

17 2
LCO 3.4.3 All jet pumps shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.8.1 2 17 | -------------------NOTES-------------------<br>1. Not required to be performed until 4 hours after associated recirculation loop is in operation.<br><br>2. Not required to be performed until 24 hours after > 25% RTP.<br>------------------------------------------- | |
| | Verify at least two of the following criteria (a, b, and c) are satisfied for each operating recirculation loop:<br><br>17 recirculation pump speed<br>a. Recirculation loop drive flow versus ~~flow control valve position~~ differs by ≤ 10% from established patterns.<br><br>b. Recirculation loop drive flow versus total core flow differs by ≤ 10% from established patterns.<br><br>c. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns, or each jet pump flow differs by ≤ 10% from established patterns. | 24 hours |

3 ~~Reviewer's Note: An acceptable option to these criteria for jet pump OPERABILITY can be found in the BWR/4 ITS, NUREG-1433.~~

4 SRVs
3.4.4
17 3
— ≥ 25% RTP
5

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.4 Safety/Relief Valves (S/RVs) 4

17 3

LCO 3.4.4 The safety function of ~~[seven]~~ 12 2 4 S/RVs shall be OPERABLE, with two SRVs in the lowest two lift setpoint groups OPERABLE. 6

AND

6 ~~The relief function of [seven] additional S/RVs shall be OPERABLE.~~

APPLICABILITY: ~~MODES 1, 2, and 3.~~ THERMAL POWER ≥ 25% RTP. 5

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| 7 ~~A. One [required] S/RV inoperable.~~ | ~~A.1 Restore [required] S/RV to OPERABLE status.~~ | ~~14 days~~ |
| 7 ~~B.~~ A. ~~Required Action and associated Completion Time of Condition A not met.~~<br><br>~~OR~~<br><br>2 ~~[Two]~~ One or more ~~[required]~~ S/RVs 4 inoperable. | ~~B.1~~ A.1 7 ~~Be in MODE 3.~~ Reduce THERMAL POWER to < 25% RTP. 5<br><br>~~AND~~<br><br>~~B.2 Be in MODE 4.~~ 5 | ~~12~~ 4 hours 5<br><br>~~36 hours~~ 5 |

A

A

– 2.25% RTP (5)

S/RVs 3.4.4 (3) (17) (4) 1C

## SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.4.1 (17) (3) | Verify the safety function lift setpoints of the {required} (2) S/RVs (4) are as follows:<br><br>Number of S/RVs (4) / Setpoint (psig)<br>~~[8] [1165 ± 34.9]~~<br>~~[6] [1180 ± 35.4]~~<br>~~[6] [1190 ± 35.7]~~ (2)<br><br>~~Following testing, lift settings shall be within ± 1%.~~ (8) | ~~{~~In accordance with the Inservice Testing Program ~~or [18] months}~~ (2) |
| ~~SR 3.4.4.2~~ | ~~NOTE: Valve actuation may be excluded.~~<br><br>~~Verify each [required] relief function S/RV actuates on an actual or simulated automatic initiation signal.~~ (6) | ~~[18] months~~ |
| SR 3.4.~~4~~.~~3~~ (3) (17) (2) (6) | ~~NOTE: Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test.~~ (5)<br><br>Verify each {required} (2) S/RV (4) opens when manually actuated. | ~~[18]~~ (24) (2) months ~~on a STAGGERED TEST BASIS for each valve solenoid~~ (6) |

| | |
|---|---|
| 2 | 1165 ± 34.9 |
| 4 | 1175 ± 35.2 |
| 4 | 1185 ± 35.5 |
| 4 | 1195 ± 35.8 |
| 4 | 1205 ± 36.1 |

(2)



<INSERT SPECIFICATION 3.4.4> (5)

1C

5 ~~INSERT SPECIFICATION 3.4.4~~ *

S/RVs
3.4.4

— < 25% RTP 5

3.4 REACTOR COOLANT SYSTEM (RCS) 4

3.4.4 Safety/Relief Valves (S/RVs) — < 25% RTP

LCO 3.4.4 The safety function of ~~[seven]~~ four 2 S/RVs 4 shall be OPERABLE.

~~AND~~

6 ~~The relief function of [seven] additional S/RVs shall be OPERABLE.~~

APPLICABILITY: MODE 1 with THERMAL POWER < 25% RTP, MODES 2 and 3. 5

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| 7 ~~A. One [required] S/RV inoperable.~~ | ~~A.1 Restore [required] S/RV to OPERABLE status.~~ | ~~14 days~~ |
| 7 A. ~~Required Action and associated Completion Time of Condition A not met.~~ <br> ~~OR~~ <br> 2 One ~~[Two]~~ or more ~~[required]~~ S/RVs 4 inoperable. | A.1 7 Be in MODE 3. <br> AND <br> A.2 7 Be in MODE 4. | 12 hours <br> <br> <br> 36 hours |

* THIS SPECIFICATION INSERT WAS ADDED TO MEET THE SPECIFIC REQUIREMENTS OF WNP-2.



Insert Page 3.4-8a

5 INSERT SPECIFICATION 3.4.4
(continued)

— ≤25% RTP 5

4
S~~/~~RVs
3.4.4

## SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.4.1 | Verify the safety function lift setpoints of the ~~[required]~~ 2 S~~/~~RVs 4 are as follows:<br><br>Number of S~~/~~RVs 4 — Setpoint (psig)<br><br>~~[8] — [1165 ± 34.9]~~<br>~~[6] — [1180 ± 35.4]~~<br>~~[6] — [1190 ± 35.7]~~ 2<br><br>~~Following testing, lift settings shall be within ± 1%.~~ 8 | ~~[~~In accordance with the Inservice Testing Program 2 ~~or [18] months]~~ |
| ~~SR 3.4.4.2~~ | ~~-----NOTE-----~~<br>~~Valve actuation may be excluded.~~<br>~~----------~~<br>~~Verify each [required] relief function S/RV actuates on an actual or simulated automatic initiation signal.~~ | ~~[18] months~~ 6 |
| SR 3.4.4.~~3~~ 2 6 | -----NOTE-----<br>Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test.<br>----------<br>Verify each ~~[required]~~ 2 S~~/~~RV 4 opens when manually actuated. | ~~[18]~~ 24 2 months ~~on a STAGGERED TEST BASIS for each valve solenoid~~ 6 |

| | |
|---|---|
| 2 | 1165 ± 34.9 |
| 4 | 1175 ± 35.2 |
| 4 | 1185 ± 35.5 |
| 4 | 1195 ± 35.8 |
| 4 | 1205 ± 36.1 |

2



Insert Page 3.4-8b

 C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.5 RCS Operational LEAKAGE C

LCO 3.4.5 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. ≤ 5 gpm unidentified LEAKAGE; ~~[and]~~ 2

2 c. ≤ ~~[30]~~ 25 gpm total LEAKAGE averaged over the previous 24 hour period; ~~[~~and 2

d. ≤ 2 gpm increase in unidentified LEAKAGE within the previous ~~[4]~~ 24 2 hour period in MODE 1~~]~~. 2

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. Unidentified LEAKAGE not within limit.<br><br>OR<br><br>Total LEAKAGE not within limit. | A.1 Reduce LEAKAGE to within limits. | 4 hours |
| B. Unidentified LEAKAGE increase not within limit. | B.1 Reduce~~d~~ 9 LEAKAGE increase 13 to within limit.<br><br>OR | 4 hours B<br><br>(continued) |

|C

ACTIONS

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

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | FREQUENCY |
|---|---|
| SR 3.4.5.1 Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits. | ~~8~~ hours <br> 12 {10} |

|C

C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

C

LCO 3.4.6 The leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1 and 2,
MODE 3, except valves in the residual heat removal (RHR) 13 shutdown cooling flow path when in, or during the transition to or from, the shutdown cooling mode of operation.

ACTIONS

-----NOTES-----
1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by PIVs.

---

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or more flow paths with leakage from one or more RCS PIVs not within limit. | -----NOTE----- Each check valve used to satisfy Required Action A.1 ~~and Required Action A.2~~ shall have been verified to meet SR 3.4.6.1 and be in the reactor coolant pressure boundary ~~[or the high pressure portion of the system]~~. 11 12 | |
| | | (continued) |

B

C

1C

ACTIONS

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| A. (continued) | A.1 | Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve. | 4 hours |
| | AND | | |
| | A.2 | ~~Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.~~ | ~~72 hours~~ |
| B. Required Action and associated Completion Time not met. | B.1 | Be in MODE 3. | 12 hours |
| | AND | | |
| | B.2 | Be in MODE 4. | 36 hours |

C

SURVEILLANCE REQUIREMENTS

| | SURVEILLANCE | FREQUENCY |
|---|---|---|
| SR 3.4.6.1 | Only 5 1 and 2<br>13 ----------------------NOTE----------------------<br>~~Not~~ required to be performed in MODE ~~3~~.<br>--------------------------------------------------<br><br>Verify equivalent leakage of each RCS PIV is ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm, at an RCS pressure ~~≥ [1040] psig and ≤ [1060]~~ ≥ 1035 psig. 2 | In accordance with Inservice Testing Program ~~or [18] months~~ 2 |

The actual test pressure shall be ≥ 935 psig.

C

B

C

C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.7 RCS Leakage Detection Instrumentation

LCO 3.4.7 The following RCS leakage detection instrumentation shall be OPERABLE:

a. Drywell floor drain sump flow 4 monitoring system; ~~{and}~~ 2

b. One channel of either drywell atmospheric particulate or atmospheric gaseous monitoring system ~~[and]~~.

~~c. Drywell air cooler condensate flow rate monitoring system].~~ 2

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. Drywell floor drain sump flow 4 monitoring system inoperable. | ------------NOTE------------<br>LCO 3.0.4 is not applicable.<br>----------------------------<br>A.1 Restore drywell floor drain sump flow monitoring system to OPERABLE status. | 30 days |

(continued)

1C

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
| --- | --- | --- |
| B. Required drywell atmospheric monitoring system inoperable. | ------------NOTE------------ LCO 3.0.4 is not applicable. --------------------------- | |
| 2 | B.1 Analyze grab samples of drywell atmosphere. | Once per 12 hours |
| | AND | |
| 2 | B.2 Restore required drywell atmospheric monitoring system to OPERABLE status. | 30 days |
| 12 C. ~~Drywell air cooler condensate flow rate monitoring system inoperable.~~ | ~~------------NOTE------------ Not applicable when the required drywell atmospheric monitoring system is inoperable. ---------------------------~~ | |
| | ~~C.1 Perform SR 3.4.7.1.~~ | ~~Once per 8 hours~~ |
| 12 D. ~~Required drywell atmospheric monitoring system inoperable.~~ | ~~------------NOTE------------ LCO 3.0.4 is not applicable. ---------------------------~~ | |
| ~~AND~~ | ~~D.1 Restore required drywell atmospheric monitoring system to OPERABLE status.~~ | ~~30 days~~ |
| ~~Drywell air cooler condensate flow rate monitoring system inoperable.~~ | ~~OR~~ | |

(continued)

1C

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| 12 [D. (continued)] | [D.2 Restore drywell air cooler condensate flow rate monitoring system to OPERABLE status.] | [30 days] |
| 12 C ~~E~~. Required Action and associated Completion Time of Condition A, B 12 or ~~, C, or D~~ not met. 2 | C ~~E~~.1 Be in MODE 3. <br> AND C 12 <br> C ~~E~~.2 Be in MODE 4. | 12 hours <br><br> 36 hours |
| 12 D ~~F~~. All required leakage detection systems inoperable. | D ~~F~~.1 12 Enter LCO 3.0.3. | Immediately |

<INSERT SR NOTE> 14

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | FREQUENCY |
|---|---|
| SR 3.4.7.1 Perform CHANNEL CHECK of required drywell atmospheric monitoring system. | 12 hours 1C |
| SR 3.4.7.2 Perform CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation. | 31 days 1C |
| SR 3.4.7.3 Perform CHANNEL CALIBRATION of required leakage detection instrumentation. | ~~[18]~~ months 2 1C |

1A

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.8 RCS Specific Activity

1C

LCO 3.4.8 The specific activity of the reactor coolant shall be limited to DOSE EQUIVALENT I-131 specific activity ≤ [0.2] 2 μCi/gm.

≤ 9

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

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. Reactor coolant specific activity 2 > [0.2] μCi/gm and ≤ 4.0 μCi/gm DOSE EQUIVALENT I-131. | -------------NOTE----------- <br> LCO 3.0.4 is not applicable. <br> --------------------------- | |
| | A.1 Determine DOSE EQUIVALENT I-131. | Once per 4 hours |
| | <u>AND</u> | |
| | A.2 Restore DOSE EQUIVALENT I-131 to within limits. | 48 hours |
| B. Required Action and associated Completion Time of Condition A not met. <br> <u>OR</u> <br> Reactor coolant Specific activity 2 > [4.0] μCi/gm DOSE EQUIVALENT I-131. | B.1 Determine DOSE EQUIVALENT I-131. | Once per 4 hours |
| | <u>AND</u> | |
| | B.2.1 Isolate all main steam lines. | 12 hours |
| | <u>OR</u> | |
| | | (continued) |

1C

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. (continued) | B.2.2.1 Be in MODE 3.<br><br>AND<br><br>B.2.2.2 Be in MODE 4. | 12 hours<br><br><br><br>36 hours |

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.8.1 | -------------------NOTE--------------------<br>Only required to be performed in MODE 1.<br>------------------------------------------<br><br>Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is 2 ≤ ~~[~~0.2~~]~~ μCi/gm. | 7 days |

1C

C

C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown

LCO 3.4.9 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

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

1. Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up to 2 hours per 8 hour period.

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

---------------------------------------------------------------

less than

APPLICABILITY: MODE 3 with reactor steam dome pressure ~~<~~ the RHR cut ~~-~~ in permissive pressure~~]~~. 2

ACTIONS

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

1. LCO 3.0.4 is not applicable.

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

---------------------------------------------------------------------------------

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

ACTIONS

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

1C

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.9.1 | -------------------NOTE------------------- Not required to be met until 2 hours after reactor steam dome pressure is less than the RHR cut in permissive pressure]. ------------------------------------------ | 2 |
| | Verify one RHR shutdown cooling subsystem or recirculation pump is operating. | 12 hours |

1C

1C

1C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown

LCO 3.4.10 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

---------------------------NOTES--------------------------
1. Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up to 2 hours per 8 hour period.

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

APPLICABILITY: MODE 4.

ACTIONS

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

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or two RHR shutdown cooling subsystems inoperable. | A.1 Verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem. | 1 hour<br><u>AND</u><br>Once per 24 hours thereafter |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. No RHR shutdown cooling subsystem in operation.<br><br>AND<br><br>No recirculation pump in operation. | B.1 Verify reactor coolant circulating by an alternate method.<br><br>AND | 1 hour from discovery of no reactor coolant circulation<br><br>AND<br><br>Once per 12 hours thereafter |
| | B.2 Monitor reactor coolant temperature and pressure. | Once per hour |

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | FREQUENCY |
|---|---|
| SR 3.4.10.1 Verify one RHR shutdown cooling subsystem or recirculation pump is operating. | 12 hours |

1C
1C
1C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.11 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.11 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation ~~pump starting~~ loop temperature requirements shall be maintained within ~~the~~ limits. ~~specified in the PTLR.~~ 17 17

15

APPLICABILITY: At all times.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. ---------NOTE--------- Required Action A.2 shall be completed if this Condition is entered. ---------------------- | A.1 Restore parameter(s) to within limits. | 30 minutes |
| | AND | |
| | A.2 Determine RCS is acceptable for continued operation. | 72 hours |
| 13 Requirements of the LCO not met in MODE~~S~~ 1, 2, ~~and~~ or 3. | | |
| B. Required Action and associated Completion Time of Condition A not met. | B.1 Be in MODE 3. | 12 hours |
| | AND | |
| | B.2 Be in MODE 4. | 36 hours |

(continued)

C

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| C. ---------NOTE--------- Required Action C.2 shall be completed if this Condition is entered. --------------------- Requirements of the LCO not met in other than MODES 1, 2, and 3. | C.1 Initiate action to restore parameter(s) to within limits.<br>AND<br>C.2 Determine RCS is acceptable for operation. | Immediately<br><br>Prior to entering MODE 2 or 3 |

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.11.1 | -------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations, and RCS inservice leak and hydrostatic testing. ---------------------------------------------<br>17 Verify: a. RCS pressure and RCS temperature ~~, and~~ ~~RCS heatup and cooldown rates~~ are within the applicable limits specified in ~~the PTLR~~ Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3; | 30 minutes C |
| SR 3.4.11.2 | Verify RCS pressure and RCS temperature are within the criticality limits specified in ~~the PTLR~~ Figure 3.4.11-3. 17 | Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality. C |

(continued)

17 b. RCS heatup and cooldown rates are ≤ 100°F in any 1 hour period; and
c. RCS temperature change during inservice leak and hydrostatic testing is ≤ 20°F in any 1 hour period when the RCS pressure and RCS temperature are not within the limits of Figure 3.4.11-2. C

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.11.3 | --------NOTE--------<br>Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup ~~with reactor steam dome pressure ≥ 25 psig~~.<br>12 16<br>Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is ~~within the limits specified in the PILR~~ ≤ 145°F. 17 | Once within 15 minutes prior to each startup of a recirculation pump |
| SR 3.4.11.4 | --------NOTE--------<br>Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup.<br>Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is ~~within the limits specified in the PILR~~ ≤ 50°F. 17 | Once within 15 minutes prior to each startup of a recirculation pump |
| <INSERT SR 3.4.11.5><br><INSERT SR 3.4.11.6> 15 | | |
| SR 3.4.11.5 7 7 15 | --------NOTE--------<br>Only required to be performed when tensioning the reactor vessel head bolting studs.<br>Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PILR~~ ≥ 80°F. 17 | 30 minutes |

(continued)

1 C

INSERT SR 3.4.11.5 and 3.4.11.6

| | | |
|---|---|---|
| SR 3.4.11.5 | ---------------------NOTE--------------------- Only required to be met in single loop operation with THERMAL POWER ≤ 25% RTP or the operating recirculation loop flow ≤ 10% rated loop flow. ----------------------------------------------- <br><br> Verify the difference between the bottom head coolant temperature and the RPV coolant temperature is ≤ 145°F. | <br><br><br><br> Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow |
| SR 3.4.11.6 | ---------------------NOTE--------------------- Only required to be met in single loop operation when the idle recirculation loop is not isolated from the RPV, and with THERMAL POWER ≤ 25% RTP or the operating recirculation loop flow ≤ 10% rated loop flow. ----------------------------------------------- <br><br> Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is ≤ 50°F. | <br><br><br><br> Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow |

C

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.11.~~6~~ 8 15 | --------------------NOTE--------------------<br>Not required to be performed until 30 minutes after RCS temperature ≤ ~~80~~ 90 4 °F in MODE 4.<br>--------------------------------------------<br><br>Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PTLR.~~ 17 ≥80°F | 30 minutes |
| SR 3.4.11.~~7~~ 9 15 | --------------------NOTE--------------------<br>Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4.<br>--------------------------------------------<br><br>Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PTLR.~~ 17 ≥80°F | 12 hours |

C C C C C

17

Insert Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3

C

17

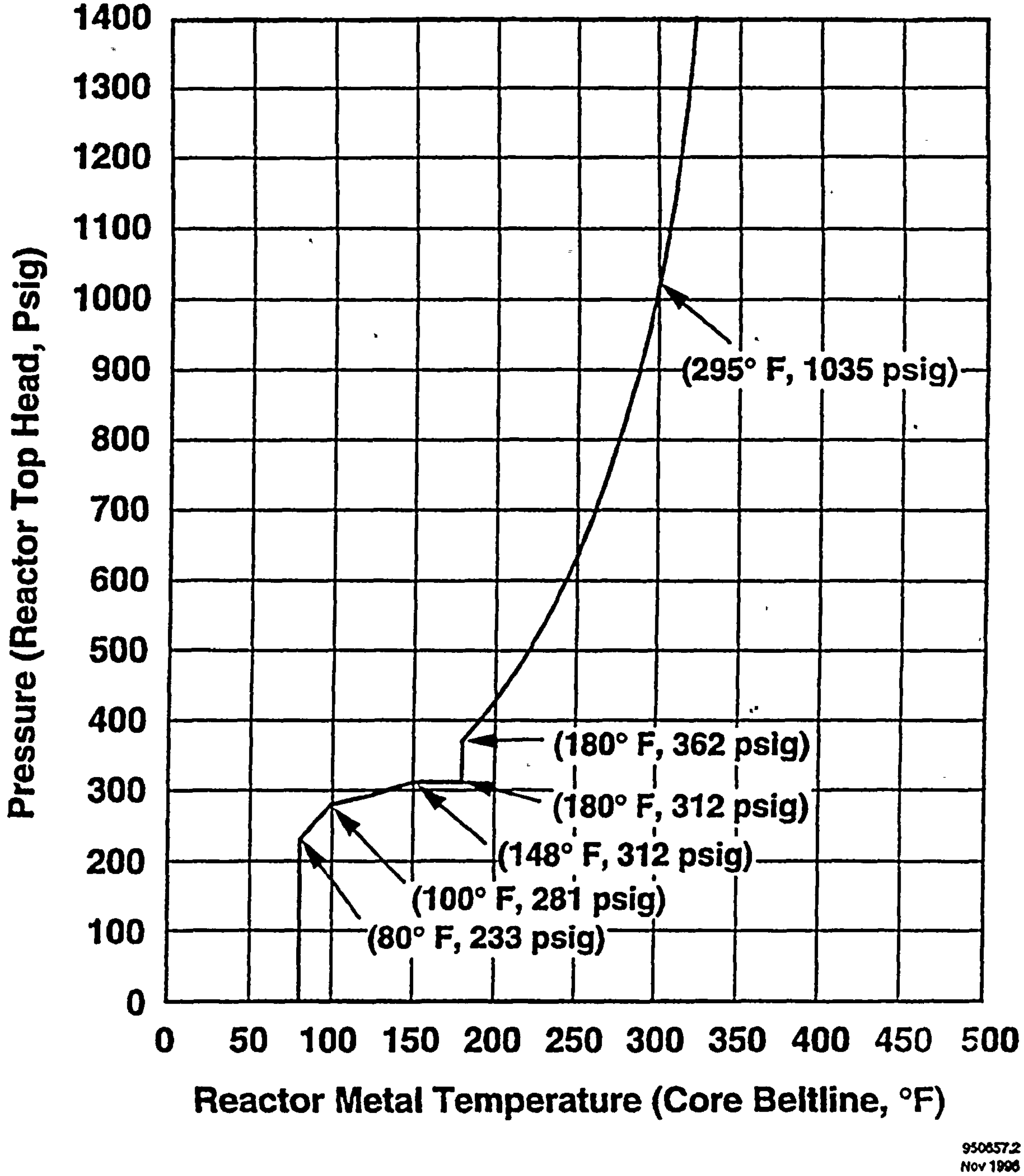
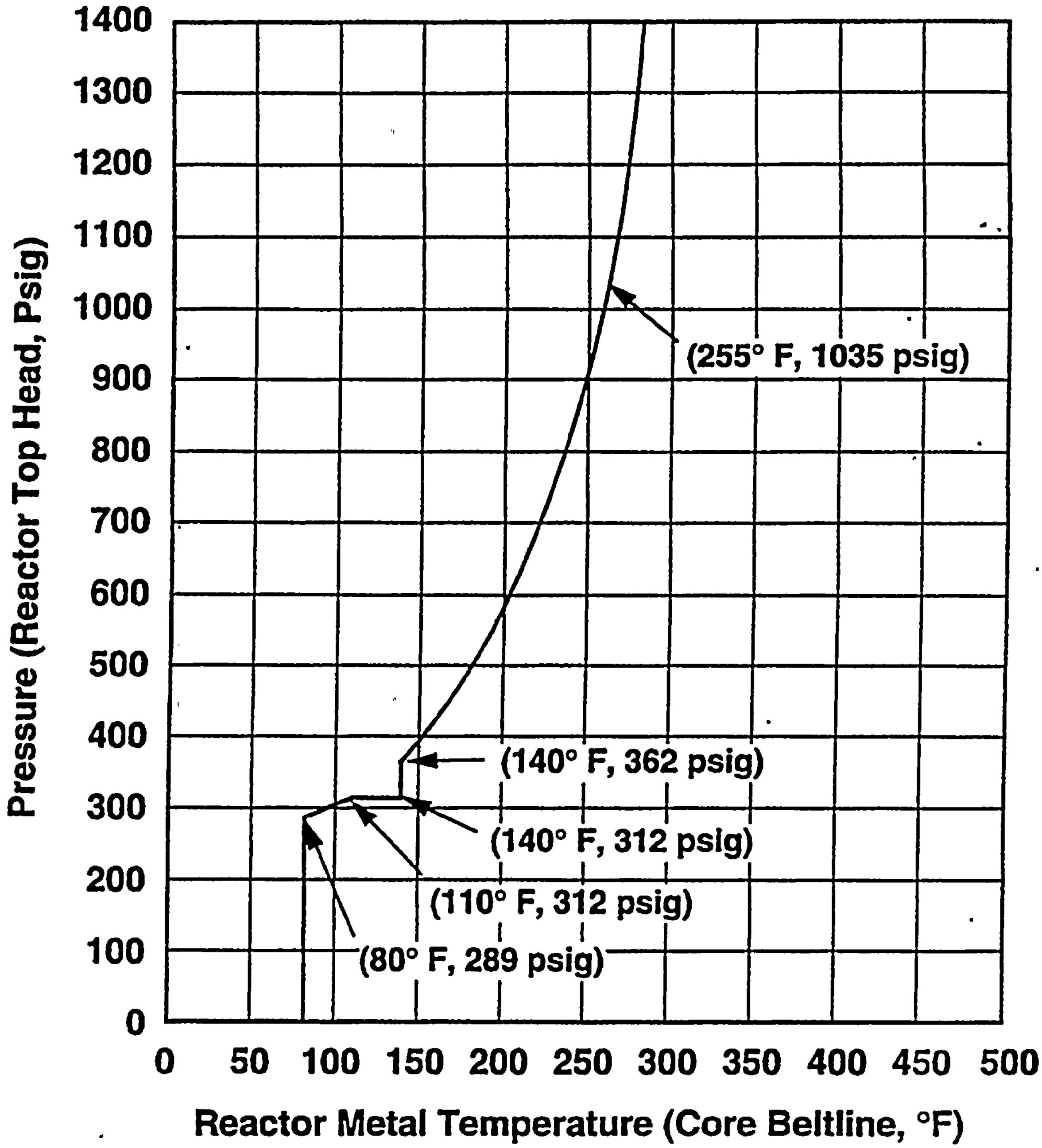



Figure 3.4.11-3 (Page 1 of 1)
Nuclear Heating and Cooldown Curve

C

Insert Page 3.4-27c

17




950657.3
Nov 1996

Figure 3.4.11-2 (Page 1 of 1)
Non-Nuclear Heating and Cooldown Curve

Insert Page 3.4-27b

17

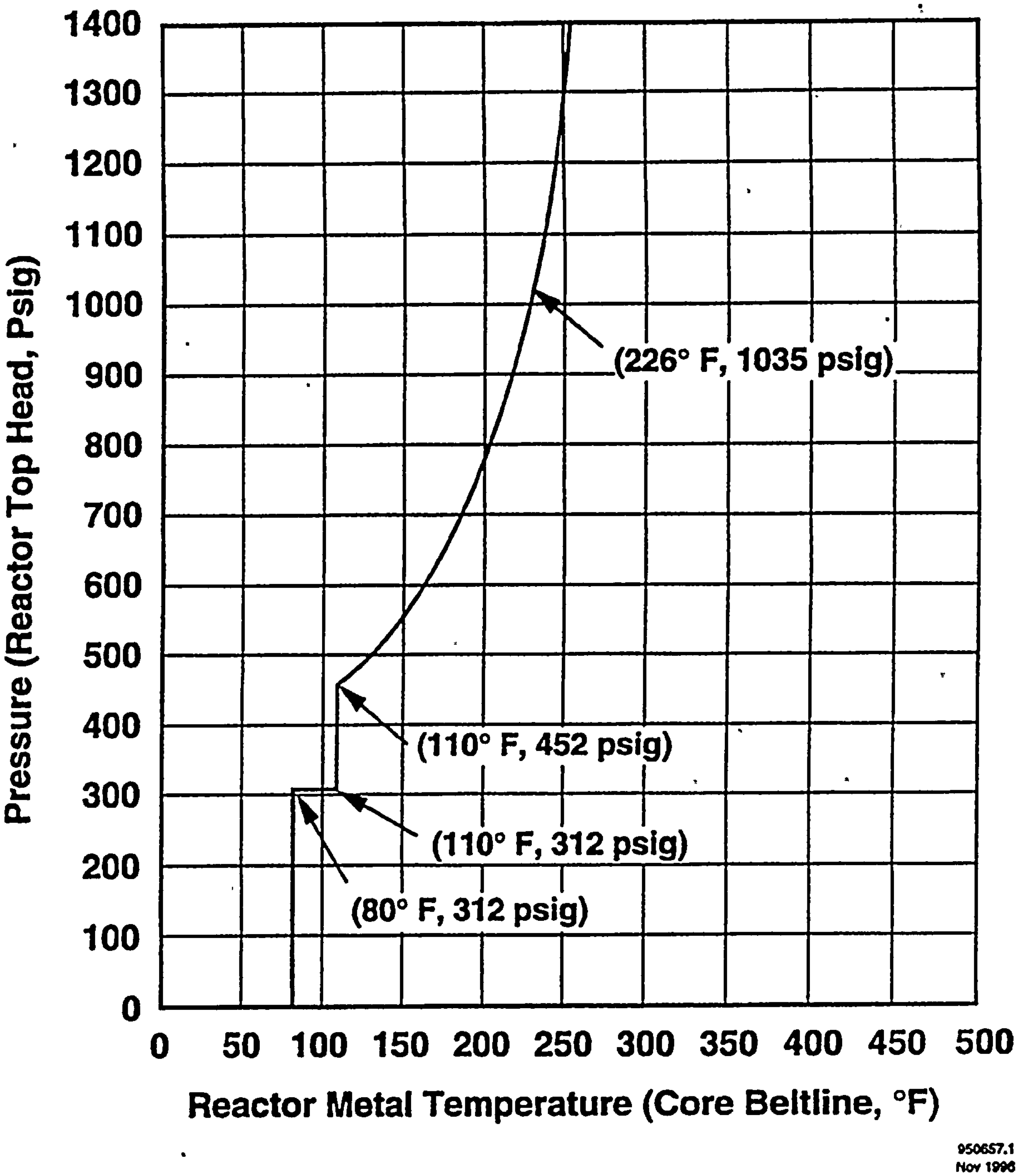



Figure 3.4.11-1 (Page 1 of 1)
Inservice Leak and Hydrostatic Testing Curve

Insert Page 3.4-27a

C

## 3.4 REACTOR COOLANT SYSTEM (RCS)

### 3.4.12 Reactor Steam Dome Pressure

1035 (2)

LCO 3.4.12 The reactor steam dome pressure shall be ≤ [1045] psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. Reactor steam dome pressure not within limit. | A.1 Restore reactor steam dome pressure to within limit. | 15 minutes |
| B. Required Action and associated Completion Time not met. | B.1 Be in MODE 3. | 12 hours |

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.4.12.1 | Verify reactor steam dome pressure is ≤ [1045] psig.<br>1035 (2) | 12 hours |

## JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
## SECTION 3.4 - REACTOR COOLANT SYSTEM

1. The "Recirculation Loops Operating" Specification has been revised to reflect Current Licensing Basis requirements related to core thermal hydraulic stability.

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

3. This Reviewer's Note has been deleted. This Note provides the location of an alternative set of criteria that is not used at WNP-2. This is not meant to be retained in the final version of the plant specific submittal.

4. The proper WNP-2 plant specific nomenclature/value has been provided.

5. The WNP-2 overpressure protection safety analysis assumes 12 SRVs are OPERABLE when THERMAL POWER is $\geq$ 25% RTP and only four SRVs are OPERABLE when THERMAL POWER is $\leq$ 25% RTP. Therefore, the NUREG Specification has been divided into two separate Specifications, LCO 3.4.3 and LCO 3.4.4, 1C with the appropriate ACTIONS and Surveillances for the given condition (i.e., above or below 25% RTP). This splitting of the Specification due to the different number of SRVs required is consistent with the ITS philosophy. 1C

6. The Current WNP-2 DBA small break LOCA Licensing Basis analysis assumes not only 12 SRVs to be OPERABLE, but also that the 12 required SRVs must include two SRVs in the lowest two lift setpoint groups. This ensures the ECCS performance assumed in the analysis is met. Therefore, this requirement has been added to NUREG LCO 3.4.4. In addition, the Current WNP-2 Licensing Basis does not include Technical Specification requirements for the relief mode of the SRVs since the overpressure protection analysis does not assume the relief mode functions to mitigate an overpressurization event. Therefore, the relief mode requirements have been deleted. The following requirements have been renumbered, where applicable, to reflect this deletion.

7. This bracketed requirement has been deleted because it is not applicable to WNP-2. The Current Licensing Basis does not require an additional SRV to meet the single failure criterion, thus the ACTION is not needed. The following requirements have been renumbered to reflect this deletion.

8. The current WNP-2 Licensing Basis does not require the SRV setpoints to be reset to $\pm$ 1% following testing. This allowance was approved on 5/2/95 in Amendment Number 137.

9. Typographical/grammatical error corrected.

10. The Surveillance Frequency has been extended from 8 hours to 12 hours consistent with Generic Letter 88-01, Supplement 1. The supplement allowed the Frequency to be once per shift, not to exceed 12 hours. This is also consistent with the Current Licensing Basis.

11. Required Action A.2, which requires the high pressure portion of the affected system to be isolated from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve, has been deleted. The Current Licensing Basis for WNP-2 does not include closing a second valve. As described in the WNP-2 response to Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," WNP-2 tests the valves and if one is found to be leaking beyond the allowable limits, the penetration will be isolated by one valve that meets the leakage limits. This will preclude an intersystem LOCA from occurring on the affected system. Therefore, the Required Action is not needed. In addition, the Note to Required Action A.1 has been modified to reflect this deletion. Required Action A.1 Note has also been modified to only apply to a check valve, consistent with Current Licensing Basis.

12. The bracketed requirement/information has been deleted since it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect this deletion.

13. Editorial changes have been made to achieve consistency with the Writer's Guide.

14. A Note has been added to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances, provided the other Leakage Detection System channel is OPERABLE. This Note is similar to other Notes in the ITS, which allow channels that provide automatic actions to be inoperable for up to 6 hours. This instrumentation only provides indication, and the 6 hour allowance is not allowed unless the other channel is OPERABLE. This change has previously been approved at Georgia Power Company's Plant Hatch Units 1 and 2, in amendments 185 and 125, respectively.

15. The words in the LCO have been changed from "pump starting" to "loop" since the Current WNP-2 Licensing Basis includes additional recirculation loop requirements. These additional requirements have been added as proposed SRs 3.4.11.5 and 3.4.11.6. The following requirements have been renumbered due to this addition. C

16. The Notes to NUREG SR 3.4.11.3 and SR 3.4.11.4 have been modified to only require the SRs to be met during the recirculation pump startup. This is when the actual stresses occur, and when the SRs really need to be met (consistent with Current Licensing Basis). The added words are consistent with the wording currently in the Bases for 3.4.11 (LCO Section, item c), which states the following; "The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel meets the limit of the PTLR during recirculation pump startup." C

17. The utilization of a Pressure and Temperature Limits Report (PTLR) requires the development, and NRC approval, of detailed methodologies for future revisions to P/T limits. At this time, the Supply System does not have the necessary methodologies submitted to the NRC for review and approval. Therefore, the proposed presentation removes references to the PTLR and proposes that the specific limits and curves be included in the P/T Limits Specification (LCO 3.4.11). C

18. WNP-2 has recently modified the Reactor Recirculation System to add an adjustable speed drive (ASD) to control the speed of the reactor recirculation pump. As part of this modification, the flow control valves are now locked open. Therefore, the requirement to maintain and test the valves was deleted in Amendment 145 to the current Technical Specifications. The following Specifications have been renumbered to reflect this deletion. C

D

## 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

### 3.5.1 ECCS — Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of [eight] six 1 safety/relief valves shall be OPERABLE. B

APPLICABILITY: MODE 1,
MODES 2 and 3, except ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ [150] psig. 1

ACTIONS

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| A. One low pressure ECCS injection/spray subsystem inoperable. | A.1 | Restore low pressure ECCS injection/spray subsystem to OPERABLE status. | 7 days |
| B. High Pressure Core Spray (HPCS) System inoperable. | B.1 | Verify by administrative means RCIC System is OPERABLE when RCIC is required to be OPERABLE. | ~~1 hour~~ Immediately 3 |
| | AND | | |
| | B.2 | Restore HPCS System to OPERABLE status. | 14 days |

C

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| C. Two ECCS injection subsystems inoperable.<br><br>OR<br><br>One ECCS injection and one ECCS spray subsystem inoperable. | C.1 | Restore one ECCS injection/spray subsystem to OPERABLE status. | 72 hours |
| D. Required Action and associated Completion Time of Condition A, B, or C not met. | D.1 | Be in MODE 3. | 12 hours |
| | AND | | |
| | D.2 | Be in MODE 4. | 36 hours |
| E. One required ADS valve inoperable. 4 | E.1 | Restore ADS valve to OPERABLE status. | 14 days |
| F. One required ADS valve inoperable. 4<br><br>AND<br><br>One low pressure ECCS injection/spray subsystem inoperable. | F.1 | Restore ADS valve to OPERABLE status. | 72 hours |
| | OR | | |
| | F.2 | Restore low pressure ECCS injection/spray subsystem to OPERABLE status. | 72 hours |
| G. 4 Two or more required ADS valves inoperable.<br><br>OR 5 | G.1 | Be in MODE 3. | 12 hours |
| | AND | | |
| | | | (continued) |

<MOVE FROM NEXT PAGE> 5

C

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.5.1.7 | ------------------NOTE------------------<br>Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test.<br>----------------------------------------------<br><br>Verify each required 4 ADS valve opens when manually actuated. | 24 1<br>~~[18]~~ months on a STAGGERED TEST BASIS for each valve solenoid |

C

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.5.2.5 | Verify each required ECCS pump develops the specified flow rate with ~~against a system head corresponding to~~ the specified developed head ~~reactor pressure~~.<br><br>TOTAL DEVELOPED HEAD ~~[SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF]~~<br><br>SYSTEM / FLOW RATE<br>LPCS ≥ 6350 ~~[7115]~~ gpm ≥ 128 ~~[290]~~ psig<br>LPCI ≥ [7450] gpm ≥ 26 ~~[125]~~ psig<br>HPCS ≥ 6350 ~~[7115]~~ gpm ≥ 200 ~~[445]~~ psig | In accordance with the Inservice Testing Program ~~or 92 days~~ |
| SR 3.5.2.6 | -------------------NOTE-------------------<br>Vessel injection/spray may be excluded.<br>------------------------------------------<br><br>Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal. | 24 ~~[18]~~ months |

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
SECTION 3.5 - ECCS AND RCIC SYSTEM

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

2. Not used. 1C

3. The time allowed to complete Required Action B.1 of LCO 3.5.1 and A.1 of LCO 3.5.3 has been changed from 1 hour to Immediately. Due to the mechanics of how Completion Times work, the 1 hour allowance can probably never be used. For example, if HPCS is inoperable, LCO 3.5.1, Condition B is entered, and the 1 hour verification of Required Action B.1 is performed. If RCIC is not inoperable at this time, the Required Action is met. However, since the Completion Time starts upon entry into this Condition, if RCIC later becomes inoperable, the 1 hour time in the HPCS ACTION has already expired. Thus a unit shutdown would be required immediately upon discovery of RCIC being inoperable, even though the RCIC Required Action (LCO 3.5.3, Required Action A.1) appears to allow 1 hour to verify HPCS OPERABILITY. To avoid this confusion, the original time allowed by NUREG-1434, Revision 0 and the current WNP-2 Technical Specifications has been used.

4. The words "required" has been added consistent with its use throughout the ITS.

5. Change made to be consistent with the Writer's Guide.

6. A new Surveillance Requirement, SR 3.5.1.3, which tests the ADS backup accumulators, has been added consistent with the current WNP-2 Licensing Basis. This SR replaces the NUREG SR 3.5.1.3, which ensures the ADS receiver pressure is within limits. The following requirements have been renumbered to reflect this addition.

1C

D

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. ---------NOTE--------- Only applicable to penetration flow paths with two PCIVs. ---------------------- One or more penetration flow paths with two PCIVs inoperable ~~[except for purge valve]~~ due to leakage ~~not within limit]~~. (8) | B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. | 1 hour<br>(37) TSTF-30 Changes Not shown |
| C. ---------NOTE--------- Only applicable to penetration flow paths with only one PCIV. ---------------------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit (8) | C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.<br>AND<br>C.2 ---------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. ---------------------- Verify the affected penetration flow path is isolated. | ~~[4]~~ hours except for excess flow check valves (EFCVs) AND 12 hours for EFCVs (6)<br><br>Once per 31 days for isolation devices outside primary containment (10) |
| ~~D. Secondary containment bypass leakage rate not within limit.~~<br>(8) One or more penetration flow paths with MSIV leakage rate, or hydrostatically tested lines leakage rate | D.1 Restore leakage rate to within limit. | ~~4 hours except for main steam line AND 8 hours for main steam line (11)~~<br>INSERT 3.6.1.3 COMPLETION TIME (10) |

(continued)

D

C

INSERT BWR/4 3.6.1.7 19
(Continued)

INSERT 3.6.1.7 ACTION B NOTE

22

----------NOTE----------
Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker.
------------------------

INSERT 3.6.1.7 ACTION C

22

| | | | | |
|---|---|---|---|---|
| C. | One or more suppression chamber-to-drywell vacuum breakers with two disks not closed. | C.1 | Close one open vacuum breaker disk. | 2 hours |

## 3.6 CONTAINMENT SYSTEMS

### 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One RHR suppression pool cooling subsystem inoperable. | A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status. | 7 days |
| B. Required Action and associated Completion Time of Condition A not met.<br><br>OR<br><br>Two RHR suppression pool cooling subsystems inoperable. | B.1 Be in MODE 3.<br><br>AND<br><br>B.2 Be in MODE 4. | 12 hours<br><br><br><br>36 hours |

27. THERMAL POWER in the range of 1% RTP is not readily quantified with much accuracy. While range 7 on IRMs approximates 1% RTP, this power level can also be approximated from SRMs and even by determining the point of adding heat. These acceptable options are desired to be maintained in plant procedures, with the ITS requirement as it is in the existing WNP-2 Technical Specifications; i.e., 1% RTP. Therefore, the LCO and ACTIONS have been modified to reflect the 1% RTP requirement.

28. These additional words have been deleted for consistency. These words do not appear in the BWR/4 ITS (NUREG-1433). These words were approved to be deleted from NUREG-1434, Revision 1 per change package BWR-6, C.4, but apparently were not deleted.

29. Not used. |C

30. The WNP-2 design does not include a Suppression Pool Makeup System. Therefore, this Specification has been deleted.

31. This reviewer's type of note has been deleted. This information is for the NRC reviewer to be keyed in to what is needed to meet this requirement. This is not meant to be retained in the final version of the plant specific submittal.

32. The WNP-2 design does not include Primary Containment and Drywell Hydrogen Ignitors nor a Drywell Purge System. Therefore, these Specifications have been deleted.

33. Two new Specifications have been added, proposed LCO 3.6.3.2 and proposed LCO 3.6.3.3. These Specifications are from the BWR/4 ITS (NUREG-1433), since the WNP-2 design is similar to the BWR/4 design with regards to the Primary Containment Atmosphere Mixing System and oxygen concentration requirements of the primary containment. Therefore, the BWR/4 LCOs are used and any deviations from the BWR/4 ITS are discussed. |B

34. The periodic Completion Time of "once per 12 hours" for Required Action B.1 has been deleted. The Reviewer's Note in the Bases for this Required Action states "The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability." The alternate hydrogen control function used for this Required Action is the RHR Drywell Spray System, which is in the ITS (LCO 3.6.1.5). Therefore, this additional periodic Completion Time is not needed.

35. NUREG SR 3.6.4.1.3 has been modified to only require all inner secondary containment access doors or all outer secondary containment access doors per access opening to be closed. The WNP-2 design includes more than two doors per access opening in some accesses, thus requiring all inner or all outer doors to be closed is more restrictive than the current WNP-2 Technical Specification requirements.

36. The WNP-2 design does not include a drywell internal to the primary containment (NUREG-1434 is based on a Mark III containment; WNP-2 has a Mark II containment). Therefore, the Drywell related LCOs (LCO 3.6.5.1 through LCO 3.6.5.6) have been deleted.

37. Generic change TSTF-30 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

38. Editorial change made to be consistent with other similar requirements in the ITS.

39. The words in NUREG Condition I (proposed Condition F), "or during operations with a potential for draining the reactor vessel (OPDRVs)," have been deleted. The Condition is still applicable in MODES 4 and 5, which are the only MODES that OPDRVs can be performed. In addition, there are no PCIVs required to be OPERABLE in the WNP-2 ITS whose Applicability is only during OPDRVS. The only PCIVs required when not in MODES 1, 2, and 3 are the RHR shutdown cooling isolation valves, and their Applicability is MODES 4 and 5. Therefore, the "during OPDRVs" Applicability is duplicative of the MODES 4 and 5 Applicability (which is being maintained) and can be deleted. B

40. A Primary Containment Leakage Rate Testing Program has been added to Section 5.5, consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements. The Program references the requirements of 10 CFR 50 Appendix J and approved excemptions, therefore the Surveillances have been modified to reference the Program.

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| B. One [SSW] subsystem inoperable ~~[for reasons other than Condition A]~~. 1 2 | B.1 --------NOTES-------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources—Operating," for diesel generator made inoperable by [SSW] System. 1 4 2. Enter applicable Conditions and Required Actions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for [RHR shutdown cooling] subsystem made inoperable by [SSW] System. 1 1 ------------------ Restore [SSW] subsystem to OPERABLE status. 1 | 72 hours |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| C. Required Action and associated Completion Time of Condition A or B not met.<br><br>OR<br><br>(1) Both {SSW} subsystems inoperable (2) ~~[for reasons other than Condition A]~~.<br><br>(1) [OR<br><br>{UHS} inoperable for reasons other than Condition A.] | C.1<br><br>AND<br><br>C.2 | Be in MODE 3.<br><br><br><br>Be in MODE 4. | 12 hours<br><br><br><br>36 hours |

(C)

SURVEILLANCE REQUIREMENTS

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| (1) [SR 3.7.1.1 | Verify the water level of each {UHS} (1) ~~cooling tower basin~~ (7) (spray pond) is ≥ [7.25] ft (1) (432 ft 9 inches mean sea level). | 24 hours] |
| (2) ~~[SR 3.7.1.2~~ | ~~Verify the water level [in each SSW pump well of the intake structure] is ≥ [ ] ft.~~ | ~~24 hours]~~ |
| (1) [SR 3.7.1.3 (2) | Verify the average water temperature of (each) (7) (1) {UHS} (spray pond) (7) is ≤ [ ] (77) (1) °F. | 24 hours] |

(continued)

JUSTIFICATION FOR DEVIATION FROM NUREG-1434, REVISION 1
SECTION 3.7 - PLANT SYSTEMS

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

2. This bracketed requirement has been deleted because it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect this deletion.

3. The current WNP-2 safety analysis assumes an average sediment level in the spray ponds. This proposed ACTION is essentially the current Licensing Basis ACTION when average sediment level exceeds the safety analysis limit (a minor change to the current Licensing Basis ACTION has been made, as shown in the Current Technical Specification Markup and described in the Discussion of Changes for ITS 3.7.1). The currently required SR has also been added.

4. Editorial changes have been made to achieve consistency with the Writer's Guide.

5. Not used. C

6. Not used.

7. The proper WNP-2 plant specific nomenclature/value has been provided.

8. This requirement has been deleted since the HPCS SW System uses the same water source as the SW System. The SW System requirements, covered in LCO 3.7.1, bounds the HPCS SW System water level requirements; thus it is not needed in the HPCS SW System LCO. The following requirements have been renumbered to reflect this deletion.

ACTIONS

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. (continued) | A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable. | 24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s) |
| | AND | |
| | A.3 Restore (1) required offsite circuit to OPERABLE status. | 72 hours<br>~~AND~~<br>~~24 hours from discovery of two divisions with no offsite power~~ (3)<br>AND<br>6 days from discovery of failure to meet LCO |

(continued)

10

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| B. One [required] DG inoperable. 2 | B.1 | Perform SR 3.8.1.1 for OPERABLE [required] offsite circuit(s). 1 | 1 hour<br><br>AND<br><br>Once per 8 hours thereafter |
| | AND | | |
| | B.2 | Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable. | 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) |
| | AND | | |
| | B.3.1 | Determine OPERABLE DG(s) are not inoperable due to common cause failure. | [24] hours 2 |
| | OR | | |
| | B.3.2 | Perform SR 3.8.1.2 for OPERABLE DG(s). | [24] hours |
| | AND | | |
| | B.4 | Restore required DG to OPERABLE status. | 72 hours 1a<br><br>AND<br><br>6 days from discovery of failure to meet LCO 1c |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| E. Two ~~[required]~~ DGs inoperable. (2) | E.1 Restore one ~~[required]~~ DG to OPERABLE status. (2) | 2 hours <br> OR <br> 24 hours if Division 3 DG is inoperable |
| ~~F. [One [required] [automatic load sequencer] inoperable.]~~ | ~~--------REVIEWER'S NOTE-------- This Condition may be deleted if the unit design is such that any sequencer failure mode will only affect the ability of the associated DG to power its respective safety loads following a loss of offsite power independent of, or coincident with, a Design Basis Event.~~ <br> ~~F.1 Restore [required] [automatic load sequencer] to OPERABLE status.~~ | ~~[12] hours~~ |
| ~~G~~ F. Required Action and Associated Completion Time of Condition A, B, C, D, ~~[or]~~ E ~~, or F~~ not met. | ~~G~~ F.1 Be in MODE 3. <br> AND <br> ~~G~~ F.2 Be in MODE 4. | 12 hours <br><br> 36 hours |
| ~~H~~ G. Three or more ~~[required]~~ AC sources inoperable. (2) | ~~H~~ G.1 Enter LCO 3.0.3. | Immediately |

1D

(1)

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.8.1.9 | ------------------NOTES------------------<br>1. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR.<br>2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ~~≤ [0.9]~~ as close to the power factor of the single largest post-accident load as practicable.<br>-----------------------------------------------<br>Verify each required DG rejects a load greater than or equal to its associated single largest post-accident load ~~for [Division 1 and ≥ [550] kW for Division 2] DGs and ≥ [2180] kW for [Division 3] DG~~, and:<br>~~a.~~ Following load rejection, the frequency is ≤ ~~[69]~~ 66.75 Hz.<br>~~b. Within [3] seconds following load rejection, the voltage is ≥ [3744] V and ≤ [4576] V; and~~<br>~~c. Within [3] seconds following load rejection, the frequency is ≥ [58.8] Hz and ≤ [61.2] Hz.~~ | ~~[18]~~ 24 months |

(continued)

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.8.1.10 | 1 12 5<br>------------------NOTE------------------<br>This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 2<br>------------------------------------------<br>required 7<br>Verify each DG operating at a power factor ≤ [0.9] does not trip and voltage is maintained ≤ [5000] V during and following a load rejection of a load ≥ [5450] kW and ≤ [5740] kW for [Division 1 and 2] DGs and ≥ [3300] kW and ≤ [3500] kW for [Division 3] DG.<br>12 1 2600 2 1 -3 2 DG-1 and DG-2 | 12<br>[18] months<br>24<br>4784 2 4400 |

(continued)

12 2. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating.

C

SURVEILLANCE REQUIREMENTS (continued)

| SURVEILLANCE | | FREQUENCY |
|---|---|---|
| SR 3.8.1.14 | ---------------NOTES---------------<br>1. Momentary transients outside the load, excitation current, and power factor ranges do not invalidate this test.<br><br>2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR.<br><br>3. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating.<br>-------------------------------------<br><br>Verify each required DG ~~operating at a power factor ≤ [0.9] for Division 1 and 2 DGs, and ≤ [0.9] for Division 3 DG~~ operates for ≥ 24 hours:<br><br>a. For ≥ [2] hours loaded ≥ ~~[3450]~~ 4650 kW ~~and ≤ [5740] kW~~ for ~~Division 1 and 2 DGs~~ DG-1 and DG-2, and ≥ ~~[3630]~~ 2850 kW ~~and ≤ [3830] kW~~ for ~~Division 3~~ DG-3; and<br><br>b. For the remaining hours of the test loaded ≥ ~~[3744]~~ 4400 kW ~~and ≤ [4576] kW~~ for ~~Division 1 and 2 DGs~~ DG-1 and DG-2, and ≥ ~~[3300]~~ 2600 kW ~~and ≤ [3500] kW~~ for ~~Division 3~~ DG-3. | [~~18~~ 24 months] |

(continued)

ACTIONS (continued)

| CONDITION | REQUIRED ACTION | | COMPLETION TIME |
|---|---|---|---|
| B. ~~LCO Item b. not met.~~ Division 1 or 2 required DG inoperable. 16 | B.1 | Suspend CORE ALTERATIONS. | Immediately |
| | AND | | |
| | B.2 | Suspend movement of irradiated fuel assemblies in ~~[primary and]~~ 2 secondary containment. | Immediately |
| | AND | | |
| | B.3 | Initiate action to suspend OPDRVs. | Immediately |
| | AND | | |
| | B.4 | Initiate action to restore required DG to OPERABLE status. | Immediately |
| C. ~~LCO Item c. not met.~~ Required Division 3 DG inoperable. 16 | C.1 | Declare ~~HPCS [and 2C Standby Service Water System]~~ High Pressure Core Spray System 2 inoperable. | ~~[~~72 hours~~]~~ 2 |

1. This bracketed requirement has been deleted because it is not applicable to WNP-2. The following requirements have been 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 WNP-2 design is such that the loss of one offsite circuit will result in, at most, only one division losing offsite power. When two divisions are without offsite power, both offsite circuits would have to be inoperable; thus ACTION C would apply, which requires one of the circuits to be restored within 24 hours. Therefore, this additional 24 hour Completion Time of Required Action A.3 is not needed.

4. Not used. | C

5. The proper LCO number has been used.

6. This Note has been deleted. It is not necessary to state that performance of one SR satisfies another SR. There are many other examples in the ITS where performance of one SR satisfies another SR, but this is the only time where a Note is used to state this fact. Therefore, to preclude confusion as to whether it is allowed in all the other places where a Note is not used, this Note has been deleted. The Following Notes have been renumbered to reflect this deletion.

7. This change has been made to be consistent with the ITS use of "required."

8. The diesel generator accelerated test frequency requirements are being relocated in their current licensing bases form to plant procedures, leaving the Technical Specifications periodic Surveillance Frequency as 31 days. A plant procedure implements the requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger valves specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG-1434. 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. This change is consistent with BWR STS-09, C.1, which allows relocation of the Table provided the requirements of the Reviewer's Note added on page 3.8-19 are met.

9. The proper WNP-2 plant specific nomenclature/value has been provided.

10. Typographical/grammatical error corrected.

11. On a DG start without automatic loading, only the lower voltage and frequency limits must be met within the associated time limits. The upper limits are unnecessarily conservative for an unloaded DG. Under an actual loss of offsite power condition, the DG would be immediately loaded once the minimum speed and voltage requirements, as applicable, are met, thereby limiting the overshoot. The proper steady state frequency and voltage limits are provided to ensure the unloaded DG does maintain these limits. The steady state limit does not apply to the simultaneous start of all DGs, since it is a test of starting independence, not operating independence.

12. If the offsite electrical power distribution system is lightly loaded (i.e., system voltage is high), it may not be possible to raise DG output voltage without creating an overvoltage condition on the ESF bus. Therefore, to ensure the bus voltage and supplied loads, and DG are not placed in an unsafe condition during this test, the power factor limit should not have to be met if grid voltage or ESF bus loading 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. Therefore, a Note stating this allowance has been added to proposed SR 3.8.1.10 and SR 3.8.1.14, and Note 2 to proposed SR 3.8.1.9 has been modified to provide this allowance. Due to this change, the affected Note sections have been renumbered as appropriate. In addition, the power factor limits are different for each DG. Therefore, the limits have been placed in the Bases for the applicable SRs, instead of in the actual SRs. The SRs still require the power factor limits to be met. This change is still more restrictive than current licensing basis, since currently no power factor limit is required for these SRs.

13. This kW loading value requirement has been deleted since it is already covered by the previous statement. These words do not appear in the BWR/4 ITS (NUREG-1433). These words were approved to be deleted from NUREG-1434, Revision 1 per change package BWR-17, C.2, but apparently were not deleted.

14. These limits imposed on return to steady state frequency and voltage following a single load rejection, are controlled by plant procedures, and are not presented as specific TS requirements. The specific criteria referenced would not be appropriate for certain methods of performing this test, e.g., if performed while the DG was loaded only with the single largest load. Furthermore, this criteria is not included in the WNP-2 Current Licensing Basis. In addition, due to this deletion, the load reject maximum frequency requirement has been made part of the first paragraph, instead of leaving it as part a.

15. The word has been changed from "achieves" to "maintain" for consistency with SR 3.8.1.11.

16. The WNP-2 design only provides for one offsite circuit to Division 3 onsite Class 1E electrical power distribution subsystem. This offsite circuit is common to one of the offsite circuits powering Division 1 and 2. Therefore, this statement has been deleted and the offsite circuit requirement for Division 3 is now covered by LCO 3.8.2.a. Due to this deletion, Condition A has been reworded to specifically state that it covers an inoperable offsite circuit, instead of referencing LCO item a, and for clarity, Conditions B and C have been reworded to specifically state that they cover an inoperable Division 1 or 2 DG, or Division 3 DG, as applicable.

17. This change has been made for clarity to ensure LCO 3.10.8 is entered when one <u>or more</u> required divisions are de-energized. The current words could be misinterpreted to mean that LCO 3.10.8 is entered when only one division is de-energized.

18. The words have been changed to "within limit" since the limit is different for DG-3. This is consistent with the other Required Actions of this LCO.

19. Change made to be consistent with the Writers Guide.

20. Proposed ACTION C has been added to LCO 3.8.4 and proposed ACTION D has been added to LCO 3.8.7 to provide clear direction as to what actions to take when the Division 1 250 V DC electrical power subsystem or the 250 V DC electrical power distribution subsystem is inoperable. This battery, charger, and distribution subsystem provide power to various reactor core isolation cooling system, residual heat removal and reactor water cleanup system valves, and to non-TS equipment such as plant controls, instrumentation, computer and communication equipment through a solid state inverter.

    Therefore, the 250 V DC electrical power subsystem and 250 V DC electrical power distribution subsystem are support systems for only three TS related functions. As such, the requirement to immediately declare the associated supported features inoperable is appropriate and consistent with the WNP-2 design. Due to this change: a) proposed ACTION A of LCO 3.8.4, proposed ACTION B of LCO 3.8.7, and the second Completion Time of proposed Required Action A.1 of LCO 3.8.7 have also been modified to only be applicable to the Division 1 and Division 2 125 V batteries, b) NUREG ACTION C of LCO 3.8.4 has been renumbered as ACTION D, and c) proposed Condition F of LCO 3.8.7 has been modified by the addition of the words "division with" since Division 1 has a 125 V DC electrical power distribution subsystem and a 250 V DC electrical power distribution subsystem (thus if both were inoperable, this ACTION would unnecessarily require a LCO 3.0.3 entry).

21. Not used.

B

22. Due to the WNP-2 design (spare 100% charger for the Division 1 and 2 batteries), individual battery chargers can be tested without compromising compliance with the Division 1 and 2 requirements of the LCO. The Division 3 battery would only affect the HPCS System, which is allowed to be inoperable for 14 days in accordance with proposed LCO 3.5.1. Therefore, the Mode restriction is not needed (and is not currently required by Current Licensing Basis). In addition, since the test can be performed without compromising the Division 1 and 2 DC loads, SR 3.8.4.6 is not excepted from performance when the unit is shutdown (per the Note to SR 3.8.5.1).

23. The load descriptions have been relocated to the Bases. The battery charger vendors recommend a load test that step loads the battery chargers at three distinct loads, not just a test at the 100% rating. The battery manufacturers recommend that in addition to testing at the 100% rating, the battery chargers should initially be loaded at 50% for 30 minutes, 75% for the next 30 minutes, then at the full load rating for the next 30 minutes. This description has been placed in the Bases. This relocation is similar to the NUREG allowance to relocate the battery load profile to plant controlled documents.

24. The word "values" in the third Condition of Condition B has been changed to "limits" to more closely match the LCO description. In addition, the word "Allowable" in Table 3.8.6-1 has been deleted to be consistent with the manner in which Category C "Limits" are described in the ACTIONS. This will also avoid confusion with the term "Allowable Value" used in the Instrumentation Section.

25. The words "and following" have been added to footnote a to allow the electrolyte level to be temporarily above the limit following the equalize charge as well as during the charge. As stated in the Bases for this footnote (in Table 3.8.6-1 description), IEEE-450 recommends that electrolyte level readings not be taken until 72 hours after the equalize charge. This allows time for the electrolyte temperature to stabilize and the level reading to be a "true" reading. Without the added words, the limit may not be met upon completion of the charge and unnecessary ACTIONS would have to be taken.

26. This Note is not needed and has been deleted. ACTION E states that if Division 3 electrical power distribution subsystem is inoperable, then the HPCS System is to be declared inoperable and the HPCS ACTIONS in LCO 3.5.1 taken. As soon as it is, then the Note states that Division 3 electrical power distribution subsystem is not required to be OPERABLE. Since that is the only reason that the HPCS System is inoperable, then it appears that the HPCS System could be declared OPERABLE again. As soon as this is done, the Note would apply again and HPCS would again be declared inoperable, and ACTIONS of LCO 3.5.1 again required. To alleviate this confusion, and for consistency with LCO 3.8.4, which does not have the Note, this Note has been deleted. Without the Note, when Division 3 electrical power distribution subsystem is inoperable, ACTION E will be entered and appropriate Required Actions taken.

27. The "voltage" check has been replaced with a "power availability" check since voltage indication is not available to all the AC and DC buses.

28. The word "handling" has been replaced with "movement" for consistency with other places in the TS where this Required Action appears.

## 3.10 SPECIAL OPERATIONS

### 3.10.1 Inservice Leak and Hydrostatic Testing Operation

LCO 3.10.1 The average reactor coolant temperature specified in Table 1.1-1 for MODE 4 may be changed to "NA," and operation considered not to be in MODE 3; and the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown," may be suspended, to allow performance of an inservice leak or hydrostatic test provided the following MODE 3 LCOs are met: 1C

a. LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," {Functions 1, 3, 4, and 5} of Table 3.3.6.2-1; 2

b. LCO 3.6.4.1, "{Secondary Containment}";

c. LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)"; and

d. LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABILITY: MODE 4 with average reactor coolant temperature > {200}°F. 2

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
SECTION 3.10 - SPECIAL OPERATIONS

1. Not used.

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

3. These words have been deleted for consistency with other similar references in the TS and Bases.

4. These changes were approved to be made in NUREG-1434, Revision 1 per change package BWR-18, C.72, C.77, C.79, and C.81 but apparently were not made. These changes were made to the BWR/4 ITS, NUREG-1433, Revision 1 in accordance with change package BWR-18, C.72, C.77, C.79, and C.81.

5. Typographical/grammatical error corrected.

6. The WNP-2 rod pattern control design does not include a Rod Action Control System, but a rod worth minimizer (RWM), similar to the BWR/4 design. Therefore, the LCO, ACTIONS, and Surveillances have been modified to reflect the RWM design, and are consistent with the BWR/4 ITS, NUREG-1433.

7. The Startup Test Program has been completed at WNP-2; therefore a reference is not needed.

8. The allowance provided by this Specification is not needed at WNP-2; consequently, it has been deleted.

9. The MODE 4 and 5 Applicability of LCO 3.3.8.2, "RPS Electric Power Monitoring," as it relates to control rod withdrawal, has been revised to not include MODE 4, consistent with the Applicability of RPS Functions in LCO 3.3.1.1 (See Section 3.3, Justification for Deviations, comment 44). In MODE 4, a control rod may be withdrawn from a core cell containing one or more fuel assemblies in accordance with LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown." Therefore, LCO 3.10.4 includes OPERABILITY requirements for RPS Functions and control rods (LCO 3.9.5). As a result, LCO 3.10.4 has been modified to also include requirements for the RPS Electric Power Monitoring assemblies to be OPERABLE when the RPS Functions and control rods are required to be OPERABLE.

# 5.0 ADMINISTRATIVE CONTROLS

## 5.2 Organization

### 5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the [FSAR]~~;~~ . 2

1 General Manager

b. The [Plant ~~Superintendent~~] shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant~~;~~ . 2

Chief Executive Officer 1

c. The ~~[a specified corporate executive position]~~ shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety~~; and~~ . 2

C

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

### 5.2.2 Unit Staff

The unit staff organization shall include the following:

a. ~~A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator~~

3 At least two Equipment Operators shall be assigned when the unit is in MODE 1, 2, or 3; and at least one Equipment Operator shall be assigned when the unit is in MODE 4 or 5.

(continued)

## 5.0 ADMINISTRATIVE CONTROLS

## 5.3 Unit Staff Qualifications

8

~~Reviewer's Note: Minimum qualifications for members of the unit staff shall be specified by use of an overall qualification statement referencing an ANSI Standard acceptable to the NRC staff or by specifying individual position qualifications. Generally, the first method is preferable; however, the second method is adaptable to those unit staffs requiring special qualification statements because of unique organizational structures.~~

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ~~[Regulatory Guide 1.8, Revision 2, 1987, or more recent revisions, or ANSI Standard acceptable to the NRC staff]. The staff not covered by [Regulatory Guide 1.8] shall meet or exceed the minimum qualifications of [Regulations, Regulatory Guides, or ANSI Standards acceptable to NRC staff].~~

1

Insert 5.3.1

C

1

## INSERT 5.3.1

ANSI/ANS N18.1-1971, for comparable positions described in the FSAR, except for:

a. The Operations Manager, who shall meet the requirements of ANSI/ANS N18.1-1971 with the exception that in lieu of meeting the stated ANSI/ANS requirement to hold a Senior Reactor Operator (SRO) license at the time of appointment to the position, the Operations Manager shall:

   1. Hold an SRO license at the time of appointment;

   2. Have held an SRO license; or

   3. Have been certified for equivalent SRO knowledge; and

b. The Radiation Protection Manager, who shall meet or exceed the qualifications of Regulatory Guide 1.8, Revision 1-R, May 1977.

C

# 5.0 ADMINISTRATIVE CONTROLS

## 5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating and Radioactive Effluent Release Reports required by Specification [5.6.2] and Specification [5.6.3].

2 1

c. Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   (a) sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   (b) a determination that the change(s) maintain the levels of radioactive effluent control required by pursuant to 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and do not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

10 2 13 2 6

2. Shall become effective after review and acceptance by the ~~[onsite review function]~~ General Manager and the approval of the ~~[Plant Superintendent]~~ Plant Operations Committee; and

10 1

3. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of, or concurrent with, the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made.

10

(continued)

## 5.5 Programs and Manuals

### 5.5.1 Offsite Dose Calculation Manual (ODCM) (continued)

Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

### 5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include ~~[~~the Low Pressure Core Spray, High Pressure Core Spray, Residual Heat Removal, Reactor Core Isolation Cooling, hydrogen recombiner, process sampling, containment monitoring and Standby Gas Treatment~~]~~. The program shall include the following: 1

The provisions of SR 3.0.2 are applicable to the 24 month Frequency for performing integrated system leak test activities. 11

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at 24 month ~~refueling cycle~~ intervals or less. 11

### 5.5.3 Post Accident Sampling

This program provides controls that ensure the capability to obtain and analyze reactor coolant, radioactive iodines ~~gases~~, and particulates in plant gaseous effluents and containment atmosphere samples under accident conditions. The program shall include the following: 12

a. Training of personnel;

b. Procedures for sampling and analysis; and

c. Provisions for maintenance of sampling and analysis equipment.

### 5.5.4 Radioactive Effluent Controls Program

This program, conforming ~~s~~ to 10 CFR 50.36a, provides for the control of radioactive effluents and for maintaining the doses to members of 13

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

13

b. Limitations on the concentrations from the site 13 of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentration values in ~~10 CFR 20~~ Appendix B, Table 2, Column 2 to 10 CFR 20.1001–20.2402; 1C

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents ~~in accordance with~~ 10 CFR 20.1302 and with the methodology and parameters pursuant to 13 in the ODCM; 1C

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary INSERT 5.5.4.g 13 ~~conforming to the dose associated with 10 CFR 20, Appendix B, Table 2, Column 1;~~

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each

(continued)

## 5.5 Programs and Manuals

5.5.8 (7) Ventilation Filter Testing Program (VFTP) (continued)

(15)

accordance with {Regulatory Guide 1.52, Revision 2, and ASME N510-1989} at the system flowrate specified below (± 10%): (1)

| ESF Ventilation System | Flowrate (cfm) (5) |
|---|---|
| [SGT System] (1) | [4012 to 4902] |
| [CREF System] | [900 to 1100] |

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < {0.05}% when tested in accordance with {Regulatory Guide 1.52, Revision 2, and ASME N510-1989} at the system flowrate specified below (± 10%): (1)

| ESF Ventilation System | Flowrate (cfm) (5) |
|---|---|
| [SGT System] (1) | [4012 to 4102] |
| [CREF System] | [900 to 1100] |

(1)

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in {Regulatory Guide 1.52, Revision 2}, shows the methyl iodide penetration less than the value specified below when tested in accordance with {ASTM D3803-1989} ~~at a temperature of ≤ [30°C] and~~ greater than or equal to the ~~relative humidity~~ value specified below: (1) (6)

(Method B for the SGT System and Method A for the CREF System) at a relative humidity (19)

| ESF Ventilation System | Penetration (%) | RH (%) (5) |
|---|---|---|
| [SGT System] (1) | [0.175] (1) | [70] |
| [CREF System] | [1.0] | [70] |

(8)

~~Reviewer's Note: Allowable penetration = [100% - methyl iodide efficiency for charcoal credited in staff safety evaluation]/(safety factor).~~

~~Safety factor = [5] for systems with heaters.~~
~~= [7] for systems without heaters.~~

(continued)

5.5 Programs and Manuals

5.5.8 7 **Ventilation Filter Testing Program (VFTP)** (continued)

15

d. Demonstrate for each of the ESF systems that the pressure 20 drop across the combined HEPA filters, ~~the prefilters,~~ and the charcoal adsorbers is less than the value specified below when tested ~~in~~ accordance ~~with [Regulatory Guide 1.52, Revision 2, and ASME N510-1989]~~ at the system flowrate 20 specified below [± 10%]: 1

| ESF Ventilation System | Delta P (inches wg) | Flowrate (cfm) 5 |
|---|---|---|
| [SGT System] 1 | [< 8] 1 | 4012 to 4902 |
| [CREF System] | [< 6] | 900 to 1100 |

e. [Demonstrate nominal 5 that the heaters for each of the 1 ESF systems dissipate the value specified below [± 10%] when tested in accordance with [ASME N510-1989]:] 1 1C

| ESF Ventilation System | Wattage (kW) 5 |
|---|---|
| [SGT System] 1 | 18.6 to 22.8 |
| [CREF System] | 4.5 to 5.5 |

18 MOVE THIS INSERT 5.5.7-B TO PAGE 5.0-11

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.9 8 **Explosive Gas and Storage Tank Radioactivity Monitoring Program**

15

This program provides controls for potentially explosive gas 1 mixtures contained in the ~~[Waste Gas Holdup System], [the quantity of radioactivity contained in gas storage tanks or fed into the offgas treatment system,]~~ and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. ~~The gaseous radioactivity quantities shall be determined following the methodology in [Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure"]. The liquid radwaste quantities shall be determined in accordance with [Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures"].~~ 21

1 Main Condener Offgas Treatment System

(continued)

## 5.5 Programs and Manuals

5.5.~~9~~ 8 15 **Explosive Gas and Storage Tank Radioactivity Monitoring Program** (continued)

The program shall include:

a. The limits for concentrations of hydrogen ~~and oxygen~~ 22 in the ~~Waste Gas Holdup System~~ Main Condenser Offgas Treatment System 1 and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

~~b. A surveillance program to ensure that the quantity of radioactivity contained in [each gas storage tank and fed into the offgas treatment system] is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of [an uncontrolled release of the tanks' contents]; and~~ 23

~~c.~~ b 23 A surveillance program to ensure that the quantity of radioactivity contained in all ~~outdoor~~ outside temporary 5 liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the [Liquid Radwaste Treatment System] is less than the amount that would result in concentrations ~~less~~ greater than the limits of ~~10 CFR 20,~~ 13 Appendix B, Table 2, Column 2, ~~at the nearest~~ to 10 CFR 20.1001-20.2402 13 potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents. B

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program Surveillance Frequencies. 2

5.5.~~10~~ 9 15 **Diesel Fuel Oil Testing Program**

A diesel fuel oil testing program ~~to implement~~ shall establish the 17 required testing of both new fuel oil and stored fuel oil. ~~shall be established.~~ The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following: B C

(continued)

## 5.5 Programs and Manuals

5.5.10 9 Diesel Fuel Oil Testing Program (continued)

15

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

, if gravity was not determined by comparison with the supplier's certificate, and a

1. an API gravity or an absolute specific gravity within limits, a specific gravity,

2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, 5

3. a clear and bright appearance with proper color;

25 C

5

b. Other properties for ASTM 2D fuel oil are within limits within 31 days following sampling and addition to storage tanks; and

26

in the storage tanks

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days in accordance with ASTM D-2276, Method A-2 or A-3.

C

A water and sediment content within limits or

5.5.11 10 Technical Specifications (TS) Bases Control Program

15

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

1. a change in the TS incorporated in the license; or

2 5

2. a change to the updated FSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

15 10 1 2

d. Proposed changes that meet the criteria of 5.5.11b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without

(continued)



25

¶ The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

B

# 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

8

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

13

for whom monitoring was performed, receiving an annual deep dose equivalent of

13

Collective deep dose equivalent (reported in

A tabulation ~~on~~ an annual basis of the number of station, utility, and other personnel (including contractors) ~~receiving exposures~~ > 100 mrem/yr and the associated man-rem ~~exposure~~ 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 dosimeter, thermoluminescent dosimeter (TLD), 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. [The initial report shall be submitted by April 30 of the year following initial criticality.]

5

electronic or

1

5.6.2 Annual Radiological Environmental Operating Report

8

-----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

(continued)

## 5.6 Reporting Requirements

5.6.4 Monthly Operating Reports (continued)

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:

<INSERT 5.6.5-A>

1

~~The individual specifications that address core operating limits must be referenced here.~~

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:

<INSERT 5.6.5-B>

1

~~Identify the Topical Report(s) by number, title, date, and NRC staff approval document, or identify the staff Safety Evaluation Report for a plant specific methodology by NRC letter and date.~~

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

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

32

(continued)

## INSERT 5.6.5-A

1. The APLHGR for Specification 3.2.1;
2. The MCPR for Specification 3.2.2;
3. The LHGR for Specification 3.2.3; and
4. The power-to-flow map for Specification 3.4.1.

## INSERT 5.6.5-B

1. ANF-1125(P)(A), and Supplements 1 and 2, "ANFB Critical Power Correlation," April 1990;
2. Letter, R.C. Jones (NRC) to R.A. Copeland (ANF), "NRC Approval of ANFB Additive Constants for ANF 9x9-9X BWR Fuel," dated November 14, 1990;
3. ANF-NF-524(P)(A), Revision 2 and Supplements 1 and 2, "Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors," November 1990;
4. XN-NF-85-67(P)(A), Revision 1, "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," September 1986;
5. ANF-89-014(P)(A), Revision 1 and Supplements 1 and 2, "Advanced Nuclear Fuels Corporation Generic Mechanical Design for Advanced Nuclear Fuels Corporation 9x9-IX and 9x9-9X BWR Reload Fuel," October 1991;
6. XN-NF-81-22(P)(A), "Generic Statistical Uncertainty Analysis Methodology," November 1983;
7. NEDE-24011-P-A-10-US, "General Electric Standard Application for Reactor Fuel," U.S. Supplement, March 1991;
8. NEDE-23785-1-PA, Revision 1, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," October 1984;
9. NEDO-20566A, "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K," September 1986;
10. EMF-CC-074(P)(A), "Volume 1 -- STAIF - A Computer Program for BWR Stability in the Frequency Domain, Volume 2 -- STAIF - A Computer Program for BWR Stability in the Frequency Domain, Code Qualification Report," July 1994;
11. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996; and
12. WPPSS-FTS-131(A), Revision 1, "Applications Topical Report for BWR Design and Analysis," March 1996.

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

[The individual specifications that address RCS pressure and temperature limits must be referenced here.]

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

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

32

Reviewer's Notes: The methodology for the calculation of the P-T limits for NRC approval should include the following provisions:

1. The methodology shall describe how the neutron fluence is calculated (reference new Regulatory Guide when issued).
2. The Reactor Vessel Material Surveillance Program shall comply with Appendix H to 10 CFR 50. The reactor vessel material irradiation surveillance specimen removal schedule shall be provided, along with how the specimen examinations shall be used to update the PTLR curves.
3. Low Temperature Overpressure Protection (LTOP) System lift setting limits for the Power Operated Relief Valves (PORVs), developed using NRC-approved methodologies may be included in the PTLR.
4. The adjusted reference temperature (ART) for each reactor beltline material shall be calculated, accounting for radiation embrittlement, in accordance with Regulatory Guide 1.99, Revision 2.
5. The limiting ART shall be incorporated into the calculation of the pressure and temperature limit curves in accordance with NUREG-0800 Standard Review Plan 5.3.2, Pressure-Temperature Limits.

C

(continued)

## 5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

6. The minimum temperature requirements of Appendix G to 10 CFR Part 50 shall be incorporated into the pressure and temperature limit curves.

7. Licensees who have removed two or more capsules should compare for each surveillance material the measured increase in reference temperature ($RT_{NDT}$) to the predicted increase in $RT_{NDT}$; where the predicted increase in $RT_{NDT}$ is based on the mean shift in $RT_{NDT}$ plus the two standard deviation value ($2\sigma_{\Delta}$) specified in Regulatory Guide 1.99, Revision 2. If the measured value exceeds the predicted value (increase in $RT_{NDT}$ + $2\sigma_{\Delta}$), the licensee should provide a supplement to the PTLR to demonstrate how the results affect the approved methodology.

32 1C

5.6.7 EDG Failure Reports

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures and any nonvalid failures experienced by that EDG in that time period shall be reported within 30 days. Reports on EDG failures shall include the information recommended in Regulatory Guide 1.9, Revision 3, Regulatory Position C.5, or existing Regulatory Guide 1.108 reporting requirement.

27 32 1C 1C

27 5.6.~~8~~ 6 Post Accident Monitoring (PAM) Report Instrumentation 28

When a ~~Special~~ Report is required by Condition B or ~~G~~ 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.

28 29

Reviewers Note added per TSTF-37 Not Shown

5.6.9 Tendon Surveillance Report

15

Any abnormal degradation of the containment structure detected during the tests required by the Pre-Stressed Concrete

(continued)

30

INSERT 5.7.2

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation)

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked 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 Shift Manager or Health Physics supervision on duty; and

   2. Doors and gates shall remain locked or guarded except during periods of personnel or equipment entry or exit. 1C

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 area(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: 1C

   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; 1C

30

INSERT 5.7.2
(continued)

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

(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; or

4. A radiation monitoring and indicating device in those cases where the options of Specification 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.

17. (continued)

of ESF filter ventilation systems). The other ITS programs (e.g., IST Program, Specification 5.5.6) provide the proper words, assuming that the program is already established. Therefore, these changes are bringing the VFTP and the Diesel Fuel Oil Testing Program in line with the words of the other programs.

18. The current licensing basis Surveillance Frequencies have been provided. In addition, for clarity, the NUREG discussion concerning the provisions of SR 3.0.2 and SR 3.0.3 have been moved from the end of this Specification to just after the discussion of the Frequencies, since it applies only to the Frequencies.

19. The Temperature requirement has been deleted to be consistent with current licensing basis. In addition, since the temperature requirement has been deleted, the relative humidity requirement has been editorially changed to be consistent with the words used in proposed Specifications 5.5.7.a, 5.5.7.b, and 5.5.7.d.

20. Proposed Specification 5.5.7.d demonstrates that the pressure drop across the HEPA filters and charcoal adsorbers is less than the specified pressure drop when tested at the specified system flow rate. The referenced methods for performing the test, Regulatory Guide 1.52 and ASME N510-1989 do not provide the methods for performing this test. As a result, these test method references have been deleted. In addition, WNP-2 does not currently require prefilter pressure drop tests, thus the prefilter requirement has also been deleted. B

21. The provisions in the NUREG for Waste Gas Systems are for PWRs and not applicable to WNP-2. Quantities of radioactivity contained in all outdoor liquid radwaste tanks meeting the conditions of proposed Specification 5.5.8 are determined in accordance with the specified Surveillance Program (proposed Specification 5.5.8.b). Therefore, the sentence in the introductory paragraph is not necessary to specify a method to determine liquid radwaste quantities.

22. The requirement to limit oxygen in the Main Condenser Offgas Treatment System has been deleted consistent with current licensing basis.

23. These provisions are only for PWRs and are not applicable for WNP-2. Due to this deletion, the following Specification has been renumbered.

24. Not used. C

25. The Fuel Oil Testing Program requirements have been modified to be consistent with current licensing basis.

26. These words have been added for clarity.

27. This requirement has been deleted in accordance with the guidance of Generic Letter 94-01. WNP-2 will implement a maintenance program for monitoring and maintaining diesel generator performance in accordance with the provisions of the maintenance rule and consistent with the guidance of Regulatory Guide 1.160. The commitment will be implemented within 90 days of issuance of the ITS license amendment. This change is consistent with BWR STS-09, C.1, which allows relocation of the Table provided the requirements of the Reviewer's Note added to this page are met. In addition, the following Specification was renumbered to reflect this deletion.

28. The acronym "PAM" has been defined, consistent with the format of the ITS, since it is the first use of this term in this Specification. The term "Instrumentation" has also been added for clarity. In addition, the term "Special Report" has been replaced by "report" since LCO 3.3.3.1 does not refer to this as a Special Report, and this report is not under the old (revision 0) header of "Special Reports."

29. The proper Condition has been provided.

30. The High Radiation Area Specification has been significantly changed to be consistent with those in the draft NRC Generic Letter on Technical Specification changes to reflect the revisions to 10 CFR 20. Minor editorial changes to the guidance provided in the draft NRC Generic Letter were made for consistency with plant specific terminology or for clarity. In addition, proposed Specification 5.7.2.a.2 provides an allowance to guard the high radiation area in lieu of locking the doors and gates to a high radiation area. This allowance is necessary for numerous reasons, including when there is a transitory high radiation area, when there is a discovery of a new high radiation area, and when establishing a temporary access to a high radiation area. 1

31. A Primary Containment Leakage Rate Testing Program has been added consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements. 1

32. The utilization of a Pressure and Temperature Limits Report (PTLR) requires the development, and NRC approval, of detailed methodologies for future revisions to P/T limits. At this time, the Supply System does not have the necessary methodologies submitted to the NRC for review and approval. Therefore, the proposed presentation removes references to the PTLR and proposes that the specific limits and curves be included in the P/T Limits Specification (proposed LCO 3.4.11). In addition, the following Specification was renumbered to reflect this deletion. 1

120

# VOLUME 9

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1a Fuel Cladding Integrity [General Electric Company (GE) Fuel] (continued)

4

indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > 50% RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 785 psig is conservative.

2 2.1.1.1b Fuel Cladding Integrity [Advanced Nuclear Fuel Corporation (ANF) Fuel]

ANFB

> 600 psia and < 1500 psia

The use of the ANF ANFB correlation is valid for critical power calculations at pressures > 580 psig > 600 psia and < 1500 psia and bundle mass fluxes > 0.25 0.1 x $10^6$ lb/hr-ft$^2$ and < 1.5 x $10^6$ lb/hr-ft$^2$ (Ref. 2). For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis: 2

5

Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ensure a minimum bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. ~~For the ANF 9x9 fuel design, the minimum bundle flow is > 30 x $10^3$ lb/hr. For the ANF 8x8 fuel design,~~ The the minimum bundle flow is > 28 x $10^3$ lb/hr. ~~For all designs, the~~ coolant minimum bundle flow and maximum flow area are such that the mass flux is ~~always~~ > 0.25 x $10^6$ lb/hr-ft$^2$. Full scale critical power tests taken at pressures down to 14.7 psia indicate that the fuel assembly critical power at 0.25 x $10^6$ lb/hr-ft$^2$ is approximately 3.35 MWt. At 25% RTP, a bundle power of approximately 3.35 MWt corresponds to a bundle radial peaking factor of > 3.0 2.9, which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 25% RTP for reactor pressures < 785 psig is conservative. C

The use of the XL-S96 correlation is valid for critical power calculations at pressures > 392 psia and < 1262 psia and bundle mass fluxes > 0.25 x $10^6$ lb/hr-ft$^2$ and < 1.55 x $10^6$ lb/hr-ft$^2$ (Ref. 3). C

(continued)

5 for Siemens Power Corporation fuel, Reference 5 describes the methodology used in determining the MCPR SL for ABB CENO fuel

BASES

APPLICABLE SAFETY ANALYSES

2 2.1.1.2b MCPR (ANF Fuel) (continued)

in the XN-3 critical power correlation. Reference 8 4 describes the methodology used in determining the MCPR SL.

5 The XN-3 critical power correlations is are based on a significant body of practical test data, providing a high degree of assurance that the critical power, as evaluated by the correlation, is within a small percentage of the actual critical power ~~being estimated~~. As long as the core pressure and flow are within the range of validity of the XN-3 correlations, the assumed reactor conditions used in defining the SL introduce conservatism into the limit because bounding high radial power factors and bounding flat local peaking distributions are used to estimate the number of rods in boiling transition. 5 ~~Still further conservatism is induced by the tendency of the XN-3 correlation to overpredict the number of rods in boiling transition.~~ ~~These~~ This conservatisms and the inherent accuracy of the XN-3 correlation provide a reasonable degree of assurance that there would be no transition boiling in the core during sustained operation at the MCPR SL. If boiling transition were to occur, there is reason to believe that the integrity of the fuel would not be compromised. Significant test data accumulated by the NRC and private organizations indicate that the use of a boiling transition limitation to protect against cladding failure is a very conservative approach. Much of the data indicate that BWR fuel can survive for an extended period of time in an environment of boiling transition.

2.1.1.3 Reactor Vessel Water Level

irradiated 7

During MODES 1 and 2, the reactor vessel water level is required to be above the top of the active fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes < 2/3 of the core height. The reactor vessel water level SL has been established at the top of the

(continued)

BASES

**APPLICABLE SAFETY ANALYSES**

2.1.1.3 Reactor Vessel Water Level (continued)

active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

**SAFETY LIMITS**

prevent 6

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

**APPLICABILITY**

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

**SAFETY LIMIT VIOLATIONS**

TSTF-05

~~2.2.1~~

~~If any SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 4).~~

~~2.2.2~~

5 6 TSTF-05

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 5). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and the probability of an accident occurring during this period is minimal.

B C

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.3

If any SL is violated, the [senior management of the nuclear plant and the utility Vice President—Nuclear Operations] shall be notified within 24 hours. The 24 hour period provides time for plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to the appropriate utility management.

TSTF-05

2.2.4

If any SL is violated, a Licensee Event Report shall be prepared and submitted within 30 days to the NRC in accordance with 10 CFR 50.73 [Ref. 6]. A copy of the report shall also be provided to the [senior management of the nuclear plant and the utility Vice President—Nuclear Operations].

B

2.2.5

If any SL is violated, restart of the unit shall not commence until authorized by the NRC. This requirement ensures the NRC that all necessary reviews, analyses, and actions are completed before the unit begins its restart to normal operation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. ~~NEDE-24011-P-A, (latest approved revision).~~ 3. UR-89-210-P-A, "SVEA-96 Critical Power Experiments on a Full Scale 24-Rod Sub-Bundles," October 1993.
4. ~~3. XN-NF524(A), Revision 1, November 1983.~~ ANF-524 (P)(A), Revision 2, including Supplements 1 and 2, November 1990.
~~4. 10 CFR 50.72.~~
6. ~~5.~~ 10 CFR 100.
~~6. 10 CFR 50.73.~~
5. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
ANF-1125 (P)(A), Revision 0, including supplements 1 and 2, April 1990.

TSTF-05

C

1C

BASES

LCO 3.0.2 (continued)

ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.11, "RCS Pressure and Temperature (P/T) Limits." 2 C

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time other conditions exist which result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed. 2

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would

(continued)

BASES (continued)

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate:

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

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed SRs. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions, and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system.

C

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support

15 2

(continued)

## B 3.1 REACTIVITY CONTROL SYSTEMS

### B 3.1.6 Rod Pattern Control

BASES

worth minimizer

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod ~~pattern controller~~ (RPC) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to [10]% RTP. The sequences effectively limit the potential amount of reactivity addition that could occur in the event of a control rod drop accident (CRDA).

WM 2

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1, 2, and 3.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1, 2, and 3. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RPC (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

4 2 C RWM 2

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage, which could result in undue release of radioactivity. Since the failure consequences for $UO_2$ have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 4), the fuel damage limit of 280 cal/gm provides a margin of safety from significant core damage, which would result in release of radioactivity (Refs. 5 and 6). Generic evaluations (Refs. 7 and 8) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 8) and the calculated offsite doses will be well within the required limits (Ref. 6).

2 5 6 2 7 8 9 2 2 C 10 7 2 2 C

(continued)

BASES

**APPLICABLE SAFETY ANALYSES (continued)**

Control rod patterns analyzed in Reference 1 follow the banked position withdrawal sequence (BPWS) described in Reference ~~9~~ 11. The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 2). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are defined to minimize the maximum incremental control rod worths without being overly restrictive during normal plant operation. The generic BPWS analysis (Ref. ~~8~~ 11) also evaluated the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods. 2 1C

Rod pattern control satisfies the requirements of Criterion 3 of the NRC Policy Statement (Ref. 12). 2 1C

**LCO**

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.

**APPLICABILITY**

In MODES 1 and 2, when THERMAL POWER is ≤ 10% RTP, the CRDA is a Design Basis Accident (DBA) and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 10% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 2). In MODES 3, 4, and 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

that allows the ~~affected control rods~~ RWM to be bypassed ~~in RACS in accordance with SR 3.3.2.1.8~~ to allow ~~insertion only~~ the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Reactor Operator or Senior Reactor Operator) or by a qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). 5

With nine or more OPERABLE control rods not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the reactor mode switch in shutdown, the reactor is shut down, and therefore does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is verified to be in compliance with the BPWS at a 24 hour Frequency, ensuring the assumptions of the CRDA analyses are met. The 24 hour Frequency of this Surveillance was developed considering that the primary check of the control rod pattern compliance with the BPWS is performed by the ~~RPC~~ RWM (LCO 3.3.2.1). The ~~RPC~~ RWM provides control rod blocks to enforce the required control rod sequence and is required to be OPERABLE when operating at ≤ 10% RTP. 2

REFERENCES

1. ~~Current Cycle Safety Analysis~~ CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996. C

2. ~~"Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners Group, July 1987.~~ Letter from T.A. Pickens (BWROG) to G.C. Laines (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1988. 2

3. FSAR, Section 15.4.~~9~~ 4.9. 3 2

~~4~~ 5. NUREG-0979, "NRC Safety Evaluation Report for GESSAR II BWR/6 Nuclear Island Design, Docket No. 50-447," Section 4.2.1.3.2, April 1983. 1C

~~5~~ 6. NUREG-0800, "Standard Review Plan," Section 15.4.9, "Radiological Consequences of Control Rod Drop Accident (BWR)," Revision 2, July 1981. 1C

(continued)



4. CENPD-284-P-A, "Control Rod Drop Accident Analysis Methodology for Boiling Water Reactors: Summary and Qualification," July 1996. C

BASES

REFERENCES (continued)

~~6.~~ 7. 10 CFR 100.11, "Determination of Exclusion Area Low Population Zone and Population Center Distance."

8. NEDO-10527, "Rod Drop Accident Analysis for Large BWRs," (including Supplements 1 and 2), March 1972.

~~7.~~ 9. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

~~8.~~ 10. ASME, Boiler and Pressure Vessel Code, Section III.

~~9.~~ 11. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

12. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

APPLICABLE SAFETY ANALYSES (continued)

allow continuous drainage of the SDV during normal plant operation to ensure the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level exceeds a specified setpoint. The setpoint is chosen such that all control rods are inserted before the SDV has insufficient volume to accept a full scram.

SDV vent and drain valves satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4) 2

LCO

The OPERABILITY of all SDV vent and drain valves ensures that, during a scram, the SDV vent and drain valves will close to contain reactor water discharged to the SDV piping. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to be open to ensure that a path is available for the SDV piping to drain freely at other times.

APPLICABILITY

In MODES 1 and 2, scram may be required, and therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. ~~This provides adequate controls to ensure that only a single control rod can be withdrawn. Also,~~ during MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram. 3 C

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required

4

(continued)

## B 3.2 POWER DISTRIBUTION LIMITS

## B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

### BASES

BACKGROUND

1, 2, and 3

1
5

The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that the fuel design limits identified in Reference 1 are not exceeded ~~during anticipated operational occurrences (AOOs)~~ and that the peak cladding temperature (PCT) during the postulated design basis loss of coolant accident (LOCA) does not exceed the limits specified in 10 CFR 50.46.

2
3

As a result, core geometry will be maintained by minimizing growth fuel cladding failure due to heatup following a design basis LOCA.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel design limits are presented in ~~the FSAR Chapters 4, 6, and 15, and in~~ References 1 and 2. The analytical methods and assumptions used in evaluating Design Basis Accidents (DBAs), ~~anticipated operational transients~~ and normal operations that determine APLHGR limits are presented in FSAR, Chapters 4, 6, and 15, and in References 1, 2, and 3.

1
2
15
1
3, 4,
5
1
6, 7
1C

2

~~Fuel design evaluations are performed to demonstrate that the 1% limit on the fuel cladding plastic strain and other fuel design limits described in Reference 1 are not exceeded during AOOs for operation with LHGR up to the operating limit LHGR. APLHGR limits are equivalent to the LHGR limit for each fuel rod divided by the local peaking factor of the fuel assembly. APLHGR limits are developed as a function of exposure and the various operating core flow and power states to ensure adherence to fuel design limits during the limiting AOOs (Refs. 2 and 3). Flow dependent APLHGR limits are determined using the three dimensional BWR simulator code (Ref. 4) to analyze slow flow runout transients. The flow dependent multiplier, $MAPFAC_f$, is dependent on the maximum core flow runout capability. $MAPFAC_f$ curves are provided based on the maximum credible flow runout transient for Loop Manual and Non Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control. Non Loop Manual operational modes allow simultaneous runout of both loops because a single controller regulates core flow.~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Based on analyses of limiting plant transients (other than core flow increases) over a range of power and flow conditions, power dependent multipliers, $MAPFAC_p$, are also generated. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram signals are bypassed, both high and low core flow $MAPFAC_p$ limits are provided for operation at power levels between 25% RTP and the previously mentioned bypass power level. The exposure dependent APLHGR limits are reduced by $MAPFAC_p$ and $MAPFAC_f$ at various operating conditions to ensure that all fuel design criteria are met for normal operation and AOOs. A complete discussion of the analysis code is provided in References 1 and 3.

2

LOCA analyses are ~~then~~ performed to ensure that the specified ~~above determined~~ APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis code is provided in Reference ~~4~~ 5 limits 5. 1 The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. The APLHGR limits specified are equivalent to the LHGR of the highest powered fuel rod assumed in the LOCA analysis divided by its local peaking factor. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the APLHGR.

1C

References 1 and 2 show that no APLHGR reduction is required.

1

For single recirculation loop operation, ~~the MAPFAC multiplier is limited to a maximum of 0.86 (Ref. 2). This limit is due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA.~~

1C

The APLHGR satisfies Criterion 2 of the NRC Policy Statement (Ref 6). 1

1C

LCO

The APLHGR limits specified in the COLR are the result of fuel design, and DBA, ~~and transient~~ analyses. <Insert LCO> ~~For two~~

2

(continued)

{2} INSERT LCO

1c

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

1 INSERT REFERENCES

1. NEDC-32115P, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, June 1993.

2. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996. C

3. XN-NF-80-19(A), "Exxon Nuclear Methodology for Boiling Water Reactors," Volumes 2, 2A, 2B, and 2C, September 1982.

4. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.

5. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996. C

6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). C

## B 3.2 POWER DISTRIBUTION LIMITS

## B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid boiling transition if the limit is not violated (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experiences boiling transition (Refs. 1 and 2), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion. 1 C

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in the FSAR, Chapters 4, 6, and 15, and References 2, 3, 4, and 5. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR ($\Delta$CPR). When the largest $\Delta$CPR is added to the MCPR SL, the required operating limit MCPR is obtained. 1 C

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency ~~(Refs. 3, 4, and 5)~~. Flow dependent MCPR limits are determined by steady state thermal hydraulic methods using the three dimensional BWR simulator code (Ref. 6) ~~and the multichannel thermal hydraulic code (Ref. 7)~~. $MCPR_f$ curves are provided based on the maximum credible flow runout transient for ~~Loop Manual and Non Loop Manual~~ operation. ~~The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control. Non Loop Manual operational modes allow simultaneous runout of both loops because a single controller regulates core flow.~~

as identified in FSAR, Chapters 15 and 15.F

(1) (2) P 3 ASD (i.e., runout of both loops) 1C 1C 1

Power dependent MCPR limits ($MCPR_p$) are determined by the three dimensional BWR simulator code and the one dimensional transient code (Ref. 8). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 25% RTP and the previously mentioned bypass power level.

1 2 1C 1

The MCPR satisfies Criterion 2 of the NRC Policy Statement (Ref. 5). 1C

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The MCPR operating limits are determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 25% RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER reaches ≥ 25% RTP is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

INSERT REFERENCES

1

1. ~~NUREG-0562, June 1979.~~

2. ~~[Plant specific current cycle safety analysis].~~

3. ~~FSAR, [Appendix 15B].~~

4. ~~FSAR, [Appendix 15C].~~

5. ~~FSAR, [Appendix 15D].~~

6. ~~XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors, Neutronics Methods for Design and Analysis," Volume 1 (as supplemented).~~

7. ~~XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX Thermal Limits Methodology Summary Description," Volume 3, Revision 2, January 1987.~~

8. ~~XN-NF-79-71(P), "Exxon Nuclear Plant Methodology for Boiling Water Reactors," Revision 2, November 1981.~~

9. ~~"BWR/6 Generic Rod Withdrawal Error Analysis," General Electric Standard Safety Analysis Report, GESSAR-II, Appendix 15B.~~

D

## 1 INSERT REFERENCES


1. XN-NF-524(A), "Exxon Nuclear Critical Power Methodology for Boiling Water Reactors," Revision 1, November 1983.

2. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.

3. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.

4. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

4

## B 3.2 POWER DISTRIBUTION LIMITS

## B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR) (Optional)

BASES

**BACKGROUND**

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

1C

**APPLICABLE SAFETY ANALYSES**

,2,3,4,5,6 1 1C

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1 and 2. 7 The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 100. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the $UO_2$ pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

5 A value of ~~1%~~ plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur 1 (Ref. ~~3~~). 8 1C

Fuel design evaluations have been performed and demonstrate 5 that the ~~1%~~ fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the operating limit specified in the COLR. The analysis also includes allowances for short term transient operation above the operating limit to account for AOOs~~, plus an allowance for densification power spiking~~. 1

The LHGR satisfies Criterion 2 of the NRC Policy Statement. Ref. 9 1A

1

LCO

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

APPLICABILITY

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

ACTIONS

A.1

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

B.1

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed

(continued)

BASES

ACTIONS

B.1 (continued)

Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

are 3 They are

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

REFERENCES 1

~~1. [Non GE Fuel Analysis].~~

~~2. FSAR, Chapter [4].~~

<INSERT REFERENCES-A>

~~3~~. NUREG-0800, Section II A.2(g), Revision 2, July 1981.

B

1

<INSERT REFERENCES-B>

1C

## 1 INSERT REFERENCES-A


1. XN-NF-85-67(A), "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload," September 1986.
2. CENPD-287-P-A, "Fuel Assembly Mechanical Design Methodology for Boiling Water Reactors," July 1996.
3. XN-NF-81-21(A), "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," Revision 1, January 1982.
4. ANF-89-014(P)(A), Revision 1 and Supplements 1 and 2, "Advanced Nuclear Fuels Corporation Generic Mechanical Design for Advanced Nuclear Fuels 9x9-IX and 9x9-9X BWR Reload Fuel," October 1991.
5. EMF-95-006, "WNP-2 Cycle 11 Plant Transient Analysis," March 1995.
6. EMF-95-007, "WNP-2 Cycle 11 Reload Analysis," March 1995.
7. FSAR, Chapter 4.


## 1 INSERT REFERENCES-B


9. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

**BACKGROUND (continued)**

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A1 and A2, B1 and B2), as shown in Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

2

Two scram pilot valves are located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each scram pilot valve is solenoid operated, with the solenoids normally energized. The scram pilot valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either scram pilot valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the scram pilot valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

2

4,5,6, 7

10

**APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY**

The actions of the RPS are assumed in the safety analyses of References 2, 3, and 4. The RPS initiates a reactor scram when monitored parameter values exceed the Allowable Values specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), and

1

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the containment by minimizing the energy that must be absorbed following a LOCA.

RPS instrumentation satisfies Criterion 3 of the NRC Policy ~~Statement~~ (Ref. 8). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis. 1C

2

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

1

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

2

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., differential pressure switch) ~~(e.g., trip unit)~~ changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for ~~calibration~~ process, and ~~some of the~~ all instrument ~~errors~~ uncertainties, except drift and calibration. The trip setpoints are ~~then determined, accounting for the remaining~~ derived from the analytic limits, corrected for process and all instrument ~~errors (e.g.,~~ uncertainties, including drift and calibration~~)~~. ~~The trip setpoints derived~~ in this manner provide adequate protection ~~because~~ instrumentation uncertainties, all process effects, and ~~calibration tolerances, instrument drift, and severe~~

2

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

RWM (2)

the movement of control rods at low power. The ~~RWL~~ prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 8). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, a generic analyses have been performed (Ref. 8) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel ~~energy deposition~~ below the 170 cal/gm fuel failure threshold criterion. 1C

9 (2) 10 (2) 5 1 i

enthalpy (1)

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed. 1C

9 (2)

The IRM System is divided into two groups of IRM channels, with four IRM channels inputting to each trip system. The analysis of Reference 8 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range. 1C

9 (2) Sm (4)

The The analysis of Reference 8 has adequate conservatism to permit an IRM Allowable Value ~~of 120 divisions of a 125 division scale~~. 1C

(1) specified in the Table (1)

The Intermediate Range Monitor Neutron Flux—High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System, the ~~RWL, and the Rod Pattern Controller (RPC)~~ provide protection against control rod withdrawal error events and the IRMs are not required.

RWM and Rod Block Monitor (2)

(continued)



(2) The IRMs are automatically bypassed when the Mode Switch is in the run position.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

~~of total core flow. The recirculation loop drive flow signals are generated by eight flow units. One flow unit from each recirculation loop is provided to each APRM channel. Total drive flow is determined by each APRM by summing up the flow signals provided to the APRM from the two recirculation loops.~~ (2)

No specific safety analyses take direct credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function. Originally, (2)

The clamped Allowable Value ~~is~~ was (2) based on analyses that ~~take~~ took (2) credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function for the mitigation of the loss of feedwater heater event. The THERMAL POWER time constant of ~~6~~ 7 seconds is based on the fuel heat transfer dynamics and provides (5) (2) a signal that is proportional to the THERMAL POWER. <INSERT 2.b (b)> (2)

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor Fixed Neutron Flux—High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux—High Function is capable of generating a trip signal to prevent fuel damage or excessive (RCS) Reactor Coolant System (1) pressure. (3, and 6) For the overpressurization protection analysis ~~of~~ (c) (2) Reference ~~2~~ (5) (2), the Average Power Range Monitor Fixed Neutron Flux—High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs) (2), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. ~~6~~ (11)) takes credit for the Average Power Range Monitor Fixed Neutron Flux—High Function to terminate the CRDA. | C

The APRM System is divided into two groups of channels with ~~four~~ three (2) APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

to be bypassed. Any one APRM channel in a trip system can Four cause the associated trip system to trip. ~~Six~~ channels of Average Power Range Monitor Fixed Neutron Flux—High with two ~~three~~ channels in each trip system arranged in a one-out-of-~~three~~ logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least ~~20~~ 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. 2 2

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

The Average Power Range Monitor Fixed Neutron Flux—High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux—High Function is assumed in the CRDA analysis (Ref. 11) that is applicable in MODE 2. However, the Average Power Range Monitor Neutron Flux—High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux—High Function is not required in MODE 2. 2 1c 1

2.d. Average Power Range Monitor—Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, ~~the electronic operating voltage is low,~~ or the APRM has too few LPRM inputs (< ~~20~~ 14), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis. 2

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Four channels of Average Power Range Monitor—Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure—High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure—High Function initiates a scram for transients that results in a pressure increase, 4 counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 4, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—High signal, not the Reactor Vessel Steam Dome Pressure-High signal), along with the SRVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

3 and 6 2 5 2 1C 2 switches

High reactor pressure signals are initiated from four pressure ~~transmitters~~ that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure—High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 ~~when~~ since the RCS is pressurized and the potential for pressure increase exists. 4

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

the MCPR SL. The Reactor Vessel Water Level—High, Level 8 Function is one of the many Functions assumed to be OPERABLE and capable of providing a reactor scram during transients analyzed in Reference 3. It is directly assumed in the analysis of feedwater controller failure, maximum demand (Ref. 4).

Reactor Vessel Water Level—High, Level 8 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level—High, Level 8 Allowable Value is specified to ensure that the MCPR SL is not violated during the assumed transient.

8

Four channels of the Reactor Vessel Water Level—High, Level 8 Function, with two channels in each trip system arranged in a one-out-of-two logic, are available and are required to be OPERABLE when THERMAL POWER is ≥ 25% RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 25% RTP, this Function is not required since MCPR is not a concern below 25% RTP.

8 5

~~6~~. Main Steam Isolation Valve—Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the Nuclear Steam Supply System and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve—Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analyses of Reference 2, the Average Power Range Monitor Fixed Neutron Flux—High Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in Reference 4 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow).

2 5 c 3, and 6 1C 2

(continued)

BASES

Primary Containment 2

8

6

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

~~9~~. ~~Drywell~~ Pressure-High (continued)

the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

primary containment 2

High ~~drywell~~ pressure 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.

switches 2

Primary Containment 2

Four channels of ~~Drywell~~ Pressure-High Function, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

The reactor scram reduces the amount of energy required to be absorbed and along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

1

7 8

~~8~~.a, b. Scram Discharge Volume Water Level-High

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated when the remaining free volume is still sufficient to accommodate the water from a full core scram. However, even though the two types of Scram Discharge Volume Water Level-High Functions are an input to the RPS logic, no credit is taken for a scram initiated from these Functions for any of the design basis accidents or transients analyzed in the FSAR. However, they are retained to ensure that the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two transmitters and trip units for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a transmitter and trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference ~~8~~. 12 2 1C

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

(continued)

BASES (continued)

ACTIONS

10

~~Reviewer's Note: Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use the times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.~~

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

A.1 and A.2

13 2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 9) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases.) If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively 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 (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken. 1C

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic for any Function would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference ~~8~~ 13 <2> for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system. 1C

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference ~~8~~ 11 <2>, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels, if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram ~~(or RPT)~~), 3 Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function ~~6~~ 5 8 (Main Steam Isolation Valve—Closure), this would require both trip systems to have each channel associated with the MSIVs in three MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip).

For Function ~~9~~ 8 8 (Turbine Stop Valve — Closure, ~~Trip Oil Pressure—Low~~) 2, this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

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

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the ~~table~~ Table 1 is Function and MODE or

(continued)

BASES (continued)

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.~~

10

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the RPS reliability analysis (Ref. 8) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary. 13 2 1C

SR 3.3.1.1.1

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

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

(continued)

8 move to page B3.3-28 as Insert SR 3.3.1.1.8.

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.3.1.1.3 (continued)~~

the total loop drive flow signals from the flow unit used to vary the setpoint are appropriately compared to a ~~calibrated~~ injection test flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. ~~Each flow signal from the respective flow unit must be ≤ 105% of the calibrated flow signal.~~ If the flow unit signal is not within the limit, the APRMs that receive an input from the inoperable appropriate ~~flow unit~~ must be declared inoperable.

~~The Frequency of 7 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.~~

SR 3.3.1.1.~~4~~ 3 8

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

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

As noted, SR 3.3.1.1.~~4~~ 3 8 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. ~~9~~ 13). 2

SR 3.3.1.1.~~5~~ 4 8

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the ~~entire~~ channel will perform the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.~~9~~ 4 (continued)

intended Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference ~~9~~. (The Manual Scram Function's CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions' Frequencies.)

SR 3.3.1.1.~~5~~ 5 and SR 3.3.1.1.~~10~~ 6

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a region without adequate neutron flux indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (initiate a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block.

The IRM/APRM and SRM/IRM overlaps are also acceptable if a 1/2 decade overlap exists.

As noted, SR 3.3.1.1.~~10~~ 6 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

channel(s) that are required in the current MODE or condition should be declared inoperable.

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

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

1130

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the ~~entire~~ channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 8.

Insert SR 3.3.1.1.8 from pages B 3.3-25 and B 3.3-26.

of SR 3.3.1.1.13

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 the 18 month Frequency.

~~SR 3.3.1.1.10~~

~~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 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.~~10~~ 12 8 (continued)

first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration 9 at THERMAL POWER ≥ ~~40~~ 30 2 % RTP to ensure that the calibration ~~remains~~ 15 9 valid.

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~40~~ 30 2 % RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine ~~Stop~~ Throttle 2 Valve ~~Trip Oil Pressure—Low~~ – Closure 2 and Turbine ~~Control~~ Governor 2 Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

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

SR 3.3.1.1.~~17~~ 15 8

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference ~~8~~ 14 3. 1 for Function 2

As noted (Note 1) 8, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on ~~an 18~~ 8 24 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every ~~18~~ 24 8 months. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Figure ~~[7]~~ 7.2.
2. FSAR, Section ~~[6.2.2]~~ 15.2.4.
~~3~~ 4. FSAR, Section [6.3.3].
~~4~~ 5. FSAR, Chapter ~~[15]~~ 5 and 15.F.
~~5~~ 9. FSAR, Section [15.4.1].
~~6~~ 10. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
~~7~~ 11. FSAR, Section ~~[15.4.9]~~ F.4.3.
~~8~~ 12. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
~~9~~ 13. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
14. Licensee Controlled Specifications Manual.

3. WNP-2 Calculation NE-02-94-66, Revision 0, November 13, 1995.

6. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.
7. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

(12) INSERT B 3.3.2.1
(continued)



BASES

and shutdown (2)

BACKGROUND (continued)

The purpose of the RWM is to control rod patterns during startup, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. (A) (1) Prescribed control rod sequences ~~are~~ (1) (is) stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses ~~feedwater flow and~~ (2) steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). The RWM is a single channel system that provides input into ~~both~~ one (2) RMCS rod block circuit~~s~~. (2)

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents inadvertent criticality as the result of a control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, each inputting into a separate RMCS rod block circuit. A rod block in either RMCS circuit will provide a control rod block to all control rods.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in References 3 and 4. (2) (C) A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event. From these responses, the fuel thermal performance as a function of RBM Allowable Value was determined. The Allowable Values are chosen as a function of power level. Based on the specified Allowable Values, operating limits are established.

(continued)



Insert Page B 3.3-52c

(12) INSERT B 3.3.2.1 (Continued)



BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

The RBM Function satisfies Criterion 3 of the NRC Policy Statement. (Ref. 5) (2)

1C

Two channels of the RBM are required to be OPERABLE, (3) with their setpoints within the appropriate Allowable Value (2) ~~for the associated power range~~, to ensure that no single instrument failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with applicable setpoint methodology.

Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for ~~calibration~~, process, and ~~some of the~~ all instrument ~~errors~~ uncertainties, except drift and calibration. The trip setpoints are ~~then determined accounting for the remaining~~ derived from the analytic limits, corrected for process and all instrument ~~errors (e.g.,~~ uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all 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~~ taken into account. (2) (1)

The RBM is assumed to (2) (30) mitigate the consequences of an RWE event when operating ≥ ~~29~~% RTP and a peripheral control rod is not selected. Below this power level, or if a peripheral control rod is selected, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Ref. 3 and 4). (2) ~~When operating < 90% RTP, analyses (Ref. 3) have shown that with an initial MCPR ≥ 1.70, no RWE event will result in exceeding the MCPR SL. Also, the analyses demonstrate that when operating at ≥ 90% RTP with MCPR ≥ 1.40, no RWE event will result in exceeding the MCPR~~ (2)

1C

(continued)



Insert Page B 3.3-52d

(12) INSERT B 3.3.2.1 (continued)



BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

~~1. Rod Block Monitor (continued)~~ (2)

~~SL (Ref. 3). Therefore, under these conditions, the RBM is also not required to be OPERABLE.~~

2. Rod Worth Minimizer

The RWM enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in (2) References ~~4, 5~~, 6, ~~and 7~~. The BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control." 1C

The RWM Function satisfies Criterion 3 of the NRC Policy Statement (Ref. 5). 1C

(2) Since the RWM is a ~~hardwired~~ system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. ~~7~~ 6). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ~~≤~~ ≤ 10% RTP. (4) When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 6 ~~5 and 7~~). (2) In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical. 1C

(continued)



Insert Page B 3.3-52e

{12} INSERT B 3.3.2.1 (Continued)



BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Mode Switch—Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is ~~required to be~~ in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch—Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis. {6}

The Reactor Mode Switch—Shutdown Position Function satisfies Criterion 3 of the NRC Policy Statement (Ref. 5). {2} 1C

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5), no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2 "Refuel Position One-Rod-Out Interlock") provides the required control rod withdrawal blocks. {1}

ACTIONS

{10} ~~[Reviewer's Note: Certain LCO Completion Times are based on approved topical reports. In order for the licensee to use the times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.]~~

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this

(continued)



Insert Page B 3.3-52f

INSERT B 3.3.2.1 (continued) 12



BASES (continued)

SURVEILLANCE REQUIREMENTS

10 ~~[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.]~~

As noted at the beginning of the SRs, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a second 1 Note to indicate that when an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. ~~9~~ 8 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 a control rod block will be initiated when necessary.

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the 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 92 days is based on reliability analyses (Ref. ~~8~~ 9 2).

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with

(continued)



Insert Page B 3.3-52i

12 INSERT B 3.3.2.1
(continued)



2 and, for SR 3.3.2.1.2 only, by attempting to select a control rod not in compliance with the prescribed sequence and verifying a selection error occurs

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.2 and SR 3.3.2.1.3 (continued)

the prescribed sequence and verifying a control rod block ~~occurs~~. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP (6) in MODE 2, and (1) ~~As noted,~~ SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 for concurrent power reduction to ≤ 10% RTP) (and if entering during a shutdown, (1) for SR 3.3.2.1.2, and ~~entry into MODE 1 when~~ THERMAL POWER reduction to (1) ≤ 10% RTP in MODE 1 for SR 3.3.2.1.3, (6) for SR 3.3.2.1.3, to perform the required Surveillance (5) (4) if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The 92 day (1) Frequencies are based on reliability analysis (Ref. ~~8~~ 9 (2)).

1C

SR 3.3.2.1.4

<INSERT SR 3.3.2.1.4> (2)

~~The RBM setpoints are automatically varied as a function of power. Three Allowable Values are specified in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values automatically change are based on the APRM signal's input to each RBM channel. Below the minimum power setpoint, the RBM is automatically bypassed. These power Allowable Values must be verified periodically to be less than or equal to the specified values.~~ If any ~~power range~~ bypass (2) setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the ~~power range~~ APRM (2) channel can be placed in the conservative condition (non-bypass) (2) ~~(i.e., enabling the proper RBM setpoint)~~. If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.~~8~~ 7 (8). The ~~18 month~~ 92 day (8) Frequency is based on the actual trip setpoint methodology utilized for these channels.

11 Insert SR 3.3.2.1.5 from page B 3.3-52k

SR 3.3.2.1.~~5~~ 6 (8)

The RWM is automatically bypassed when power is above a specified value. The power level is determined from (a) (2) ~~feedwater flow and~~ (2) steam flow signal~~s~~ (2). The automatic bypass

(continued)



Insert Page B 3.3-52j

{12} INSERT B 3.3.2.1
(Continued)



BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.~~6~~ 5 8 (continued)

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

As noted, neutron detectors are excluded from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.~~6~~ 7 8

The Frequency is based upon the assumption of a~~n~~ ~~18 month~~ 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. 8

SR 3.3.2.1.8

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

REFERENCES

1. FSAR, Section ~~7.6.2.2.5~~ 7.7.1.8. 3
2. FSAR, Section ~~7.6.8.2.6~~ 7.7.1.10. 2 FSAR, Section 15.F.4.1
3. ~~NEDC-30474-P, "Average Power Range Monitor, Rod Block Monitor, and Technical Specification Improvements (ARTS) Program for Edwin I. Hatch Nuclear Plants," December 1983.~~ 2 FSAR, Section 15.F.4.3
~~4~~. ~~NEDE-24011-P-A-9-US, "General Electrical Standard Application for Reload Fuel," Supplement for United States, Section S.2.2.3.1, September 1988.~~ 6 1C
~~5. "Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners' Group, July 1986.~~ 2
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). 2 1C

(continued)

6. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996. 1C



Insert Page B 3.3-52m

INSERT B 3.3.2.1
(continued)

{12}



BASES

REFERENCES (continued)

{2} 6. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

7 ~~8~~. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.

{2}

9 ~~8~~. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.

8 ~~9~~. GENE-770-06-1-A {2}, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," ~~February 1991~~. {2} December 1992



Insert Page B 3.3-52a

{13} INSERT B 3.3.2.2 (continued)



BASES

ACTIONS (continued)

C.1

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater and main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

{10}

~~[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 Safety Evaluation Report (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 feedwater and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. ~~4~~ 3) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pump turbines and main turbine will trip when necessary. {2} (C)

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter

(continued)



Insert Page 3.3-52S

13 INSERT B 3.3.2.2
(continued)



BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.3 (continued)

calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of an ~~18~~ 24 8 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater stop valves 2 and main turbine throttle 2 valves is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a valve is incapable of operating, the associated instrumentation would also be inoperable. The ~~18~~ 24 8 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 8 month Frequency.

REFERENCES

1. FSAR, Section ~~15.1~~ 15.F.1.2 3.

3 ~~2~~. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," ~~February 1991~~ December 1992. 2 | C

2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132), 2 | C



Insert Page 3.3-52u

BASES (continued)

ACTIONS

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

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

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel ~~(or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function)~~, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval. 2

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions in accordance with Specification 5.6.~~8~~, which

8 - 6

1C

(continued)

BASES

ACTIONS (continued)

~~D~~.1 D 8

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met ~~any~~ the 1 Required Action of Condition C ~~or D, as applicable~~ 8 and the associated Completion Time has expired, Condition ~~D~~ D 8 is entered for that channel and provides for transfer to the appropriate subsequent Condition.

~~E~~.1 E 8

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C ~~or D~~ 8 is not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

~~F~~.1 F 8

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant but rather to follow E 8 1C the directions of Specification 5.6.~~8~~. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

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

INSERT SR 8

(continued)

BASES

drive motor

BACKGROUND (continued)

2 per recirculation pump. One trip system trips one of the two EOC-RPT breakers for each recirculation pump and the second trip system trips the other EOC-RPT breaker for each recirculation pump.

drive motor

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2 The T G V Closure, ~~Trip Oil Pressure-Low~~ and the T G V Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux and pressurize ation transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in References 2, 3, 4, and ~~4~~. 5 2 4 | C

| C

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of initial closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT as specified in the COLR are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when turbine first stage pressure is < ~~40%~~ RTP. 30% 3 THERMAL POWER, as sensed by 2 T G 2 2 1

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 6). 2 | C

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.~~2~~. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time. 2 8

MOVE TO NEXT PAGE 1

Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. A channel is inoperable if

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

③ ⑧

experience, to reduce THERMAL POWER to < 60% RTP from full power conditions in an orderly manner and without challenging plant systems.

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.

⑩

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 8) 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. ⑦ ② 1C

### SR 3.3.4.1.1

①

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

The Frequency of 92 days is based on reliability analysis (Ref. 8).

⑦ ② 1C

### SR 3.3.4.1.2

⑧

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the setting is discovered to be less conservative than the

(continued)

all changes are 2 unless otherwise identified

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.4 (continued)

Operating experience has shown these components usually pass the Surveillance test when performed at the ~~18~~ 24 month Frequency. 8

MOVE TO PREVIOUS PAGE 11

SR 3.3.4.1.~~5~~ 3 8

This SR ensures that an EOC-RPT initiated from the T~~S~~V-Closure, ~~Trip Oil Pressure—Low~~ and T~~S~~V Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ ~~40~~% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER ≥ ~~40~~% RTP to ensure that the calibration ~~remains~~ valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~40~~% RTP either due to open main turbine bypass valves or other reasons), the affected T~~S~~V-Closure, ~~Trip Oil Pressure—Low~~ and T~~S~~V Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

The Frequency of 18 months is based on engineering judgement and reliability of the components. ~~has shown that channel bypass failures between successive tests are rare.~~

SR 3.3.4.1.~~6~~ 5 8

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference ~~3~~ 8.

A Note to the Surveillance states that breaker ~~interruption~~ arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.~~7~~ 6. This is allowed since the ~~time to open the contacts after energization of the trip coil and the~~ arc suppression time ~~are~~ is short and do~~es~~ not appreciably change,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.6 (continued)

due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on a ~~n 18~~ 24 month STAGGERED TEST BASIS. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, the ~~18~~ 24 month Frequency is consistent with the ~~typical industry~~ refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.4.1.6

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

REFERENCES

1. FSAR, Appendix H ~~Figure [ ] (EOC-RPT instrumentation logic)~~.
2. FSAR, Section [5.2.2].
3. FSAR, Sections 15.2.2, [15.~~1.1~~ 2.3], [15.~~1.2~~ 2.5], and [15.~~1.3~~ 2.6].
4. FSAR, Section ~~s [5.5.16.1] and [7.6.10]~~ 15.F.2.1.
5. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. GENE-770-06-1, "Bases for Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," ~~February 1991~~ December 1992.
8. ~~FSAR, Section [5.5.16.2]~~ Licensee Controlled Specifications Manual.

## B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not, {but should}, occur, to lessen the effects of an ATWS event. 1 Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level—Low Low, Level 2 or Reactor Vessel Steam Dome Pressure—High setpoint is reached, the recirculation pump motor breakers trip. 2

The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability, circuit breakers, and switches that are necessary to cause initiation of a recirculation pump trip. The channels include electronic equipment (e.g., trip ~~units~~ relays) 2 that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel ~~output relay actuates, which then~~ outputs an ATWS-RPT signal to the trip logic. 2

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure—High and two channels of Reactor Vessel Water Level—Low Low, Level 2, in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Water Level—Low Low, Level 2 or two Reactor Vessel Steam Dome Pressure—High signals are needed to trip a trip system. 2 The outputs of the channels in a trip system are combined in a logic so that one ~~either~~ trip system ~~will~~ trip ~~both~~ one of one recirculation pumps (by tripping the respective ~~fast speed~~ drive motor ~~and low frequency motor generator (LFMG) motor breakers~~ breakers), while the other trip system trips the other recirculation pump. 2 C

~~There is one fast speed motor breaker and one LFMG breaker provided for each of the two recirculation pumps for a total of four breakers. The output of each trip system is provided to all four breakers.~~ 2

(continued)

BASES

**ACTIONS** (continued)

Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ATWS-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ATWS-RPT instrumentation channel.

<u>A.1 and A.2</u>

1

With one or more channels inoperable, but with ATWS-RPT trip capability for each Function maintained (refer to Required Action B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desirable to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

for one of the recirculation pumps

8

for both of the recirculation pumps

7

C

(continued)

BASES

BACKGROUND

Diesel Generators (continued)

Feature (ESF) buses if a loss of offsite power occurs. (Refer to Bases for LCO 3.3.8.1.) 3

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

,4, 5 and 6 2

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. 1C

ECCS instrumentation satisfies Criterion 3 of the NRC Policy Statement. Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion. 1C

(Ref. 7) 2

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. Each ECCS subsystem must also respond within its assumed response time. Table 3.3.5.1-1, footnote (b), is added to show that certain ECCS instrumentation Functions are also required to be OPERABLE to perform DG initiation ~~and actuation of other Technical Specifications (TS) equipment~~. 8 1C

8 injection/spray

Allowable Values are specified for each ECCS Function specified in the table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived

relay 2

1

(continued)

BASES All changes are 2 unless otherwise indicated

uncertainties, except drift and calibration

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived all from the analytic limits, corrected for ~~calibration,~~ process, and ~~some of the~~ instrument ~~errors~~. The trip setpoints are ~~then determined, accounting for the remaining~~ derived from the analytic limits, corrected for process and all uncertainties, including instrument ~~errors (e.g.,~~ drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and 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~~ taken into account. 1

Insert ASA

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or DG) initiation to mitigate the consequences of a design basis accident or transient. To ensure reliable ECCS and DG function, a combination of Functions is required to provide primary and secondary initiation signals.

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

Low Pressure Core Spray and Low Pressure Coolant Injection Systems

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

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated DGs are initiated at Level 1 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The Reactor Vessel Water Level—Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel Water Level—Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break (Refs. 2, 4, 5, and 6). C ~~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.~~ 5

(continued)

INSERT ASA

Some Functions 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. C

All changes are 2 unless otherwise indicated



8 2.d, 2.e

1.d, 1.e,

LPCS and LPCI Pumps A, B, and C Start - LOCA Time Delay Relay and LPCI

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 2.c. ~~Low Pressure Coolant Injection~~ Pump A and ~~Pump~~ B Start - Time Delay Relay (continued) LOCA/LOOP

complete before starting the second pump on the same 4.16 kV emergency bus and short enough so that ECCS operation is not degraded.

LOCA and LOCA/LOOP

Channel of

Each ~~LPCI~~ Pump Start - Time Delay Relay Function is only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the LPCI subsystems.

8 f f 8 Vessel

1.~~d~~, 2.~~d~~. Reactor ~~Steam Dome~~ Pressure - Low (Injection Permissive)

Vessel

Low reactor ~~steam dome~~ pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor ~~Steam Dome~~ Vessel Pressure - Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel ~~Steam Dome~~ Pressure - Low Function is directly assumed in the analysis of the recirculation line break (Ref. 2 ,4, 5, and 6). 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. 5 C

Vessel switches

The Reactor ~~Steam Dome~~ Pressure - Low signals are initiated from four pressure ~~transmitters~~ that sense the reactor dome pressure. ~~The four pressure transmitters each drive a master and slave trip unit (for a total of eight trip units).~~

(one pressure switch for each low pressure ECCS injection valve)

The Allowable Value is low enough to prevent overpressurizing the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

Each Vessel

~~Three~~ channels of Reactor ~~Steam Dome~~ Pressure - Low 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

(one per valve) is

(continued)

All changes are 2 unless otherwise indicated



BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8 f Vessel

1.~~d~~, 2.~~d~~. Reactor ~~Steam Dome~~ Pressure—Low (Injection Permissive) (continued)

initiation. ~~(Three channels are required for LPCS and LPCI A, while three other channels are required for LPCI B and LPCI C.)~~ Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

8 g h 8 g LPCS and LPCI Minimum Flow

1.~~e~~, 1.~~f~~, 2.~~e~~. ~~Low Pressure Coolant Injection and Low Pressure Core Spray~~ Pump Discharge Flow—Low ~~(Bypass)~~

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not ~~fully~~ sufficiently open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The LPCI and LPCS Pump Discharge Flow—Low Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flows assumed during the transients and accidents analyzed in References 1, 2, ~~and~~ 3 , 4, 5, and 6 C 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.

indicating switch 1

One flow ~~transmitter~~ per ECCS pump is used to detect the associated subsystem~~s~~' flow rate~~s~~. The logic is arranged such that each ~~transmitter~~ indicating switch causes its associated minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for ~~10~~ 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 ~~(for RHR A and RHR B)~~. The Pump Discharge Flow—Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of Pump Discharge Flow—Low Function (one LPCS channel and three LPCI channels) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE, to ensure that no single instrument failure can preclude the ECCS function. Refer to LCO 3.5.1 and

(continued)

All changes are 2 unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8 g h g

1.~~e~~, 1.~~f~~, 2.~~e~~. ~~Low Pressure Coolant Injection and Low Pressure Core Spray~~ Pump Discharge Flow—Low (Bypass) (continued)

LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

i 8 h

1.~~g~~, 2.~~f~~. Manual Initiation

The Manual Initiation switch and push button channels (with two channels per switch and push button) 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 for each of the two Divisions of low pressure ECCS (i.e., Division 1 ECCS, LPCS and LPCI A; Division 2 ECCS, LPCI B and LPCI C).

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

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 (~~one~~ 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~~ 4, 5, and 6). The core cooling

5

(continued)

1C

BASES All changes are 2 unless otherwise indicated

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. Drywell Pressure—High (continued)

The Drywell Pressure—High Function is required to be OPERABLE when HPCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the HPCS Drywell Pressure—High Function are required to be OPERABLE in MODES 1, 2, and 3, to ensure that no single instrument failure can preclude ECCS initiation. In MODES 4 and 5, the Drywell Pressure—High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure—High Function's setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

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

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the HPCS injection valve to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level—High, Level 8 Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk, thus it meets Criterion 4 of the NRC Policy Statement (Ref. 7) 14.

1 ¶ Reactor Vessel Water Level—High, Level 8 signals for HPCS are initiated from two ~~level transmitters~~ differential pressure switches 1C from the narrow range water level measurement instrumentation. ~~Both Level 8 signals are required in order to close the HPCS injection valve. This ensures that no single instrument failure can preclude HPCS initiation.~~ The Reactor Vessel Water Level—High, Level 8 Allowable Value is chosen to isolate flow from the HPCS System prior to water overflowing into the MSLs.

Two channels of Reactor Vessel Water Level—High, Level 8 Function are only required to be OPERABLE when HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases. to K

3.d. Condensate Storage Tank Level—Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCS and the CST are open and, upon receiving a HPCS initiation signal, water for

(continued)

BASES

1E

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8

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

2 4, 5 and 6 Minimum Flow 2

during the transients and accidents analyzed in References 1, 2, ~~and~~ 3 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Switch — Flow switch

One flow ~~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.)~~

when flow is low with the pump running

2

The HPCS System Flow Rate—Low ~~and HPCS Pump Discharge Pressure—High~~ Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. ~~The HPCS Pump Discharge Pressure—High Allowable Value is set high enough to ensure that the valve will not be open when the pump is not operating.~~ 8

8

of HPCS System Flow Rate-Low Function

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.

9 8

3.~~h~~. Manual Initiation

Switch and

The Manual Initiation 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 push button for the HPCS System.

with two channels

2

e

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.~~h~~. 9 8 Manual Initiation (continued)

There ~~is no~~ are Allowable Value for this Function since the channel ~~is~~ mechanically actuated based solely on the position of the switch and push button. ~~One~~ Two channel of the Manual Initiation Function ~~is~~ 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.

are

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, 4, 5, and 6. 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 ~~level transmitters~~ differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. ¶ Four channels of Reactor Vessel Water Level — Low Low 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.

The Reactor Vessel Water Level — Low Low Low, Level 1 Allowable Value is ~~high enough~~ chosen to allow time for the low pressure core spray and flooding systems to initiate and provide adequate cooling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.b, 5.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the RCPB. Therefore, ADS receives one of the signals necessary for initiation from this Function in order to minimize the possibility of fuel damage. The Drywell Pressure—High is 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.

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.

8

Four channels of Drywell Pressure—High 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.

8 4.c. 5.c. ADS Initiation Timer b b

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. 5 4, 5, and 6

2 1C

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.

(continued)

BASES

8 2

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d e d LPCS LPCI

~~4.e, 4.f, 5.e~~ ~~Low Pressure Core Spray~~ and ~~Low Pressure Coolant Injection~~ Pump Discharge Pressure—High (continued)

initiation during the events analyzed in References 2 ~~and 3~~ 4, 5, and 6 | Δ 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. 2

2 Pump discharge pressure signals are initiated from eight pressure switches ~~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 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.

8 Insert 4.f, 5.e

~~4.g, 5.f ADS Bypass Timer (High Drywell Pressure)~~

~~One of the signals required for ADS initiation is Drywell Pressure—High. However, if the event requiring ADS initiation occurs outside the drywell (for example, main steam line break outside primary containment), a high drywell pressure signal may never be present. Therefore, the ADS Bypass Timer is used to bypass the Drywell Pressure—High Function after a certain time period has elapsed. Operation of the ADS Bypass Timer Function is not assumed in any accident or transient analysis. The instrumentation is retained in the TS because ADS is part of the primary success path for mitigation of a DBA.~~ 8

(continued)

INSERT 4.f, 5.e

8

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

The purpose of the Accumulator Backup Compressed Gas System Pressure—Low Function is to ensure that a safety related supply of air is available to the ADS valves during post LOCA conditions. The normal air supply to the ADS valves is non-safety related and may not be available following a LOCA. If the normal air supply pressure is low, the Accumulator Backup Compressed Gas System Pressure—Low Function will automatically align the Accumulator Backup Compressed Gas System to provide the necessary air supply to the ADS valves. The Accumulator Backup Compressed Gas System Pressure—Low Function is assumed to be OPERABLE and capable of automatically aligning the Accumulator Backup Compressed Gas System during the accidents analyzed in References 2, 4, 5, and 6. 10

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

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

BASES All changes are 2 unless otherwise identified

ACTIONS

B.1, B.2, and B.3 (continued) 8

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. ~~4~~) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same ~~Function (or in some cases, 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 1.c, 1.f, 2 Functions ~~1.c, 1.d,~~ 2.c, ~~and~~ 2.d ~~(i.e., low pressure ECCS)~~. 2.e, and 2.f 2 e For Functions 1.~~c~~ and 2.~~c~~, redundant automatic initiation capability is lost if the Function 1.~~c~~ and Function 2.~~c~~ e 8 channels are inoperable. For Functions 1.~~d~~ and 2.~~d~~, f redundant automatic initiation capability is lost if ~~two~~ one f ~~Function 1.d~~ channel~~s~~ ~~in the same trip system~~ and ~~two~~ Function 2.~~d~~ channel~~s~~ ~~in the same trip system (but not necessarily the same trip system as the Function 1.d channels)~~ 8 are inoperable. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division to be declared inoperable. However, since channels in both Divisions are inoperable, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions being concurrently declared inoperable. For Functions 1.~~c~~ e 8 and 2.~~c~~, e 8 the affected portions of the Division are LPCI A and LPCI B, respectively. For Functions 1.~~d~~ and 2.~~d~~, f 8 the

2 8 For Functions 1.c, 1.d, 2.c, and 2.d, redundant automatic initiation capability is lost if the Function 1.c or 1.d channel concurrent with the Function 2.c or 2.d channel are inoperable.

(continued)



2 8 For Functions 1.c, 1.d, 2.c, and 2.d, the affected portion of the Divisions are LPCS, LPCI A, LPCI B, and LPCI C, respectively.

BASES

ACTIONS

C.1 and C.2 (continued)

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 8) 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.

2 1C

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCS System. Automatic component initiation capability is lost if two Function 3.d channels or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCS System must be declared inoperable within 1 hour after discovery of loss of HPCS initiation capability. As noted, the Required Action is only applicable if the HPCS pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCS System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an

(continued)

BASES

ACTIONS

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

allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or Required Action D.2.2 is performed, measures should be taken to ensure that the HPCS System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCS suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Minimum Flow

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable ~~untripped~~ 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.a, 1.d, and 2.a (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.a, 1.d, and 2.a 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

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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 8 Functions 3.f ~~and 3.g~~ since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference ~~4 and~~ 8 2 C 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

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.e channel and one Function 5.e channel are inoperable, (b) one or more Function 4.e channels and one or more Function 5.e channels are inoperable, (c) one or more Function 4.f channels and one or more Function 5.e channels are inoperable, ~~or (d) one or more Function 4.g channels and one or more Function 5.f channels are inoperable.~~

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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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

8 9

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions, as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 2 4) 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

8 2 1C

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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

~~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.~~

10

As noted at the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours as follows: (a) for Functions 3.c, 3.f, 3.g, and 3.h; and (b) for Functions other than 3.c, 3.f, 3.g, and 3.h provided the associated Function or redundant Function maintains ECCS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 8) 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.

8

8

2

10

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.1

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

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

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

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the 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 analyses of Reference ~~6~~.

8 2

1C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.6 (continued)

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 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 [18] 24 month Frequency.

SR 3.3.5.1.7

This SR ensures that the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is ~~individual channel response times are~~ less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Reference ~~5~~ 9.

However, failure to meet an ECCS RESPONSE TIME due to component failure other than instrumentation does not require the associated instrumentation to be declared inoperable; only the affected component is required to be declared inoperable.

ECCS RESPONSE TIME tests are conducted on a 24 [18] month STAGGERED TEST BASIS. The 24 [18] month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. FSAR, Section [5.2].
2. FSAR, Section [6.3].
3. FSAR, Chapter [15].
4. FSAR, Section 15.F.6.
8. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.
~~5. FSAR, Section [6.3], Table [6.3-2]~~
9. Licensee Controlled Specifications Manual
5. NEDC-32115P, "Washington Public Power Supply System Nuclear Project 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
6. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.4 and SR 3.3.6.1.5

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology. 2 4

8 ~~The Frequency of SR 3.3.6.1.4 is based on the assumption of a 92 day calibration interval in the determination of equipment drift in the setpoint analysis.~~ The ~~Frequency of SR 3.3.6.1.5 is~~ Frequencies are based on the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The ~~18~~ 24 8 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 ~~18~~ 24 8 month Frequency.

SR 3.3.6.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists ~~in the (10)~~ 3 15 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test (Ref. 12). 2 The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. However, failure to meet an ISOLATION SYSTEM RESPONSE TIME due to a PCIV closure time not within limits does not require the associated instrumentation to be declared inoperable; only the PCIV is required to be declared inoperable.

(continued)



1

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.7 (continued)

8 ~~ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 7.~~

8 ~~A Note to the Surveillance states that the radiation detectors may be excluded from ISOLATION SYSTEM RESPONSE TIME testing. This Note is necessary because of the difficulty of generating an appropriate detector input signal and because the principles of detector operation virtually ensure an instantaneous response time. Response time for radiation detection channels shall be measured from detector output or the input of the first electronic component in the channel.~~

ISOLATION SYSTEM RESPONSE TIME tests are conducted on an 24 18 month STAGGERED TEST BASIS. The 18 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. 8

REFERENCES

1. FSAR, Section ~~5.3~~ 6.2.1.1 3
2. FSAR, Chapter ~~15~~ 5 and 15.F
3. ~~NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.~~

2 3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

4. FSAR, Section 15.1.3.
5. FSAR, Section 15.6.4
6 FSAR, Section 15.2.5
7. FSAR, Section 11.3.2
2

~~4.~~ 8 FSAR, Section ~~9.3.5~~ 5.2 3
9. 10 CFR 50.62. 2
~~5.~~ 10 NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," June 1989. 2
~~6.~~ 11 NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
~~7. FSAR, Section 7.3.~~ 2

2
12. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

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~~. taken into account 1 2

Insert ASA 2

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

C

4.16 kV Emergency Bus Undervoltage

8 1.c, 1.d,

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 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.

C

Divisional and 2 TR-S and Division 3 8

6 and Time Delay Function

available and are 1

Two 2 8

~~Four~~ channels of 4.16 kV Emergency Bus Undervoltage (Loss of 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~~. ~~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 2

8 INSERT 1.a, 1.b, 1.c, 1.d, 2.a, 2.b

1.g, 5 8 e 8

~~1.c, 1.d,~~ 2.c, 2.d, ~~2.e.~~ 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

(continued)

2 INSERT ASA

Some Functions 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. C

8 INSERT 1.a, 1.b, 1.c, 1.d, 2.a, 2.b

One channel of Division 1 and 2 TR-B 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated emergency bus is available and is required to be OPERABLE when the associated DG is required to be OPERABLE. C

BASES

8 1.9, 8

e e

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.e, 1.f, 1.g, 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.

2 8

Three channels of the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) — 4.16 kV Basis and — Primary Time Delay Functions per associated emergency bus are available, but only two

2 Division 1 and 2

~~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. (Four channels input to each of the three DGs.)~~ Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

— 4.16 kV Basis and — Primary Time Delay

2 8 INSERT 1.e, 1.f, 1.g, 2.c, 2.d-1 C

2 INSERT 1.e, 1.f, 1.g, 2.c, 2.d-2 8

8 2

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)

{2}{8} INSERT 1.e, 1.f, 1.g, 2.c, 2.d - 1

One channel of Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Secondary Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. Two channels of Division 3 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function and Time Delay Function are available and required to be OPERABLE when the associated DG is required to be OPERABLE. 1C

{8} INSERT 1.e, 1.f, 1.g, 2.c, 2.d - 2

Note (a) has been added for the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) protection requirements to ensure the required Degraded Voltage—4.16 kV Basis and —Primary Time Delay Functions are associated with one another, since only two of the available channels for each Function are required to be OPERABLE.

BASES

Insert Actions A and B

ACTIONS (continued) 8

C ~~A.1~~

With one or more channels of a Function inoperable, the Function ~~may~~ is not ~~be~~ 2 capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action ~~A~~.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip ~~would result in a~~ bus transfer and DG initiation), Condition ~~B~~ D must be entered and its Required Action taken. 2 8

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.

D
~~B.1~~, D.2.1, and D.2.2 8

If any Required Action and associated Completion Time of Condition B or C is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately (Required Action D.1). Insert D.2.1 and D.2.2 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 2

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

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains ~~DG~~ 2 initiation capability. Initiation capability is maintained provided the following can be initiated by the Function (i.e., Loss of Voltage and Degraded Voltage) for two of the three DGs and 4.16 kV ESF buses: DG start, disconnect from the offsite power source, transfer to the alternate offsite power source, if available, DG output breaker closure, and load shed. Upon completion of the Surveillance,

(continued)

(8)

INSERT A.1 and B.1/B.2

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.8.1-1. The applicable Condition specified in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function result in loss of voltage initiation capability being lost for a DG. Initiation capability is lost if a) both Function 1.a channels for a division are inoperable, b) both Function 1.b channels for a division are inoperable, c) both Function 2.a channels are inoperable, or d) both Function 2.b channels are inoperable. In this situation (loss of initiation capability for a division), the 24 hour allowance of Required Action B.2 is not appropriate and the DG associated with the inoperable channels must be declared inoperable within 1 hour. This ensures that the proper loss of initiation capability check is performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Completion Time only begins upon discovery that a DG cannot be automatically initiated due to inoperable channels within the Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels. C

Because of the redundancy of sensors available to provide initiation signals and the redundancy of the onsite AC power source design, an allowable out of service time of 24 hours is provided to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would cause the initiation.

8

INSERT D.2.1 and D.2.2

Alternately, for Functions 1.c and 1.d only, the TR-B loss of voltage instrumentation, the offsite circuit supply breaker to the associated 4.16 kV ESF bus must be opened immediately (Required Action D.2.1) and the associated offsite circuit declared inoperable immediately (Required Action D.2.2). These alternate Required Actions also provide appropriate compensatory measures since the TR-B loss of voltage instrumentation only affects the loss of voltage trip capability of the alternate offsite circuit.

D

BASES

ACTIONS

8 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. B

<Insert SR> 8

E.1

Insert E.1a, from previous page

Insert E.1b, from previous page

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 1 ~~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~~ 3). 2

SR 3.3.8.2.2 1C

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

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.2 (continued)

The Frequency is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 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 the 18 month Frequency.

REFERENCES

1. FSAR, Section ~~8~~8.3.1.1 ~~5~~ 6 3

~~2.~~ 3 NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

2 2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

### B 3.4.1 Recirculation Loops Operating

RRC 1

BASES

---

BACKGROUND 2

at a faster rate

1

RRC

The Reactor ~~Coolant~~ Recirculation RRC System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes ~~more~~ 2 heat from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The RRC ~~recirculation~~ system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The ~~Reactor Coolant Recirculation~~ RRC System 1 consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable 1 ~~a two~~ speed motor driven recirculation pump, a two channel adjustable speed drive (ASD) unit to control pump speed ~~a flow control valve~~, and 2 associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

C

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the 1 driven ~~suction~~ flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and driven 1 ~~suction~~ flow are mixed in the jet pump throat section and result in partial pressure recovery 2. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

(continued)

BASES

**BACKGROUND (continued)**

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 65 to 100% RTP) without having to move control rods and disturb desirable flux patterns. <INSERT BACKGROUND> 1

Each recirculation loop is manually started from the control room. The ASD ~~recirculation flow control valves~~ provides 1 regulation of individual recirculation loop drive flows. The flow in each loop ~~can be~~ is manually ~~or automatically~~ 1 controlled. 2

**APPLICABLE SAFETY ANALYSES**

The operation of the RRC ~~Reactor Coolant Recirculation~~ System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Refs. 2, 3, and 4). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable ~~based on engineering judgement~~ (Ref. 4). 1

(continued)

1 INSERT ASA

Safety analyses performed in Refs. 1, 3, 4, and 7 implicitly assume core conditions are stable. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists (Ref. 8) depending on combinations of operating conditions (e.g., power shape, bundle power, and bundle flow).

General Electric Service Information Letter (SIL) No. 380 (Ref. 8) addressed boiling instability and made several recommendations. In this SIL, the power-to-flow map was divided into several regions of varying concern. It also discussed the objectives and philosophy of "detect and suppress." The SIL recommends that Region A be bounded by the 100% rod line and Regions B and C be bounded by the 80% rod line.

NRC Generic Letter 86-02 (Ref. 9) discussed both the GE and Siemens stability methodology and stated that due to uncertainties, General Design Criteria 10 and 12 could not be met using available analytical procedures on a BWR. The letter discussed SIL 380 and stated that General Design Criteria 10 and 12 could be met by imposing SIL 380 recommendations in operating regions of potential instabilities. The NRC concluded that regions of potential instability constituted decay ratios of 0.8 and greater by the GE methodology and 0.75 by the Siemens Power Corporation methodology which existed at that time.

Subsequently, a Siemens Power Corporation (SPC) topical report (Ref. 10) was issued which describes an improved stability computer code (STAIF) and was used to establish the current stability boundaries (Regions) for SPC fuel.

The lower boundary of Region A was defined to assure it bounds a decay ratio of 0.9. Therefore, Region A of the power-to-flow map specified in the COLR is bounded by the lower of the 100% rod line and a line that bounds a decay ratio of 0.9. Regions B and C, where applicable, were conservatively defined to bound a decay ratio of 0.75. Therefore, Region C of the power-to-flow map specified in the COLR is bounded only by the 80% rod line, and Region B is bounded by the lower of the 80% rod line and line that bounds a decay ratio of 0.75. In addition, the division between Region B and Region C is at 39% rated core flow. For ABB CENO fuel, the ABB CENO stability analysis methodology and methods (Refs. 11 and 12) are used to confirm the region boundaries described above.

BASES

LCO (continued)

applied to allow continued operation consistent with the assumptions of Reference 2. 3 1

5 <INSERT LCO>

1C

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

5 <INSERT ACTIONS>

A.1 E.1 and F.1 5

With the requirements of the LCO not met for reasons other than Condition A, B, C, D or E (e.g., one loop is "not in operation") 5, the recirculation loops must be restored to operation with matched flows within 24 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits for greater than 2 hours (i.e., Required Action E.1 has been taken) 3 5. ~~The loop with the lower flow must be considered not in operation.~~ Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

With both recirculation loops operating but the flows not matched, the recirculation loops must be restored to operation within 2 hours. If matched flows are not restored, the recirculation loop with lower flow must be declared "not in operation," as required by Required Action E.1. 3 5

Alternatively, if the single loop requirements of 5 the LCO are applied to operating limits ~~and RPS setpoints~~, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 hour and 24 hour Completion Times 5 ~~is~~ are based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large

Move rest of paragraph on next page also

(continued)

## INSERT ACTIONS (continued)

(5)

C.1

With the Required Action and associated Completion Time of Condition B not met, sufficient margin may not be available for operator response to suppress potential thermal-hydraulic oscillations since the neutron decay ratio is ≥ 0.75. As a result, action must be taken as soon as practicable to restore operation to the "Unrestricted" Region of the power-to-flow map. This can be accomplished by either decreasing THERMAL POWER with control rod insertion or increasing core flow. The starting of a recirculation pump shall not be used as a means to enter the "Unrestricted" Region. The 1 hour Completion Time provides a reasonable amount of time to complete the Required Action and is considered acceptable based on the alarms and indication provided by the ANNA System to alert the operator to a deteriorating condition. 1C

D.1

With one recirculation loop in operation in Region B of the power-to-flow map, the plant is operating in a region where the potential for thermal-hydraulic oscillations is increased and sufficient margin may not be available for operator response to suppress potential thermal-hydraulic oscillations. As a result, action must be taken as soon as practicable to restore operation to Region C or the "Unrestricted" Region of the power-to-flow map. This can be accomplished by either decreasing THERMAL POWER with control rod insertion or increasing core flow. The starting of a recirculation pump shall not be used as a means to enter the required Regions. The 1 hour Completion Time provides a reasonable amount of time to complete the Required Action and is considered acceptable based on the alarms and indication provided by the ANNA System to alert the operator of a deteriorating condition. 1C

BASES

ACTIONS

E.1 and F.1 5

A.1 (continued)

pump speeds 1 A

move to prev. page

flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing ~~flow control valve position~~ to re-establish forward flow or by tripping the pump.

G.1 5

while in a Region other than Region A of the power-to-flow map 5

~~B~~.1

With no recirculation loops in operation, or the Required Action and associated Completion Time of Condition ~~B~~ F 5 not met, the unit is required to be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

, 75.95 x 10⁶ lbm/hr 3

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., < {70}% of rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < {70}% of rated core flow. ~~The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.~~

6 6 5

recirculation loop drive

The mismatch is measured in terms of percent of rated ~~core~~ flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered ~~inoperable~~. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be

not in operation (However, for the purpose of performing SR 3.4.1.2, the flow rate of both loops shall be used) 4 B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

5 <INSERT SR 3.4.1.2>

REFERENCES

1. FSAR, Sections [6.3 ~~.3.4.~~] and 15.F.6
2. FSAR, Section [~~5.5.1.4.~~] 6.3.3.7.2.
3. ~~[3. Plant specific analysis for single loop operation.]~~

6

1 <INSERT REFERENCES>

## INSERT SR 3.4.1.2

SR 3.4.1.2

This SR ensures the combination of core flow and THERMAL POWER are within appropriate limits to prevent uncontrolled thermal-hydraulic oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal-hydraulic instability. The power-to-flow map specified in the COLR is based on guidance provided in References 8, 9, and 10. The 24 hour Frequency is based on operating experience and the operator's inherent knowledge of the reactor status, including significant changes in THERMAL POWER and core flow.

## INSERT REFERENCES


3. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.

4. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996.

5. FSAR, Section 5.4.1.1.

6. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.

7. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

8. GE Service Information Letter No. 380, "BWR Core Thermal Hydraulic Stability," Revision 1, February 10, 1984.

9. NRC Generic Letter 86-02, "Technical Resolution of Generic Issue B-19, Thermal Hydraulic Stability," January 22, 1986.

10. EMF-CC-074(P)(A), "STAIF - A Computer Program for BWR Stability in the Frequency Domain (Volume 1)" and "STAIF - A Computer Program for BWR Stability in the Frequency Domain, Code Qualification Report (Volume 2)," July 1994.

11. CENPD-294-P-A, "Thermal Hydraulic Stability Methods for Boiling Water Reactors," July 1996.

12. CENPD-295-P-A, "Thermal Hydraulic Stability Methodology for Boiling Water Reactors," July 1996.

13. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Flow Control Valves (FCVs)

BASES

BACKGROUND

The Reactor Coolant Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how this affects the design basis transient and accident analyses. The jet pumps and the FCVs are part of the Reactor Coolant Recirculation System. The jet pumps are described in the Bases for LCO 3.4.3, "Jet Pumps."

The Recirculation Flow Control System consists of the electronic and hydraulic components necessary for the positioning of the two hydraulically actuated FCVs. The recirculation loop flow rate can be rapidly changed within the expected flow range, in response to rapid changes in system demand. Limits on the system response are required to minimize the impact on core flow response during certain accidents and transients. Solid state control logic will generate an FCV "motion inhibit" signal in response to any one of several hydraulic power unit or analog control circuit failure signals. The "motion inhibit" signal causes hydraulic power unit shutdown and hydraulic isolation such that the FCVs fail "as is."

APPLICABLE SAFETY ANALYSES

The FCV stroke rate is limited to ≤ 11% per second in the opening and closing directions on a control signal failure of maximum demand. This stroke rate is an assumption of the analysis of the recirculation flow control failures on decreasing and increasing flow (Refs. 1 and 2). The closure of a recirculation FCV concurrent with a loss of coolant accident (LOCA) has been analyzed and found to be acceptable for a maximum closure rate of 11% of strokes per second (Ref. 3).

Flow control valves satisfy Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

An FCV in each operating recirculation loop must be OPERABLE to ensure that the assumptions of the design basis transient and accident analyses are satisfied.

APPLICABILITY

In MODES 1 and 2, the FCVs are required to be OPERABLE, since during these conditions there is considerable energy in the reactor core, and the limiting design basis transients and accidents are assumed to occur. In MODES 3, 4, and 5, the consequences of a transient or accident are reduced and OPERABILITY of the flow control valves is not important.

ACTIONS

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

A.1

With one or two required FCVs inoperable, the assumptions of the design basis transient and accident analyses may not be met and the inoperable FCV must be returned to OPERABLE status or hydraulically locked within 4 hours.

Opening an FCV faster than the limit could result in a more severe flow runout transient, resulting in violation of the Safety Limit MCPR. Closing an FCV faster than the limit assumed in the LOCA analysis (Refs. 1 and 2) could affect the recirculation flow coastdown, resulting in higher peak clad temperatures. Therefore, if an FCV is inoperable due to stroke times faster than the limits, deactivating the valve will essentially lock the valve in position, which

(continued)



C

BASES

ACTIONS

A.1 (continued)

will prohibit the FCV from adversely affecting the DBA and transient analyses. Continued operation is allowed in this Condition.

The 4 hour Completion Time is a reasonable time period to complete the Required Action, while limiting the time of operation with an inoperable FCV.

B.1

If the FCVs are not deactivated ("locked up") within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours. This brings the unit to a condition where the flow coastdown characteristics of the recirculation loop are not important. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

C

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

Hydraulic power unit pilot operated isolation valves located between the servo valves and the common "open" and "close" lines are required to close in the event of a loss of hydraulic pressure. When closed, these valves inhibit FCV motion by blocking hydraulic pressure from the servo valve to the common open and close lines as well as to the alternate subloop. This Surveillance verifies FCV lockup on a loss of hydraulic pressure.

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 these components usually pass the SR when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

(53)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.2.2

This SR ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits.

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 these components usually pass the SR when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [15.3.2].
2. FSAR, Section [15.4.5].
3. [Plant specific Safety Evaluation Report.]

C

1C

# B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.~~3~~ Jet Pumps 2 5

BASES

### BACKGROUND

The Reactor ~~Coolant~~ Recirculation RRC 1 System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the RRC 1 ~~Reactor Coolant Recirculation~~ System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two thirds core height, the vessel can be reflooded and coolant level maintained at two thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains ~~12~~ 10 1 jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

### APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet pumps satisfy Criterion 2 of the NRC Policy Statement (Ref. 2). 1

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the ~~Reactor Coolant Recirculation~~ RRC System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1). 1

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the ~~Reactor Coolant Recirculation~~ RRC System (LCO 3.4.1). 1

In MODES 3, 4, and 5, the ~~Reactor Coolant Recirculation~~ System is not required to be in operation, and when not in operation sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

6 2

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of

(continued)

BASES

ACTIONS

A.1 (continued)

12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.~~3~~.1 2 5

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 1 ~~2~~). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if ~~the~~ any two of the three specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. ~~2~~ 3 and ~~3~~ 4). Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while baselining new "established patterns", engineering judgement of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation ~~flow control valve (FCV)~~ pump speed operating characteristics (loop flow versus ~~FCV position~~ pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship may indicate~~s~~ a flow restriction, loss in pump hydraulic performance, leak, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the loop flow versus ~~FCV position~~ pump speed relationship must be verified.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Total core flow can be determined from measurements of the recirculation loop drive flows. Once this relationship has been established, increased or reduced total core flow for the same recirculation loop drive flow may be an indication of failures in one or several jet pumps.

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. ~~This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.~~ 9

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed ~~when~~ until 24 hours after THERMAL POWER ~~is <~~ exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.3 and 15.F.6.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
3. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.
4. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 Safety/Relief Valves (S/RVs) — ≥ 25% RTP

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (S/RVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. (However, for the purposes of this LCO, only the safety mode is required) In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston ~~or~~ cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. ~~Six of the S/RVs providing the relief function also provide the low-low set relief function specified in LCO 3.6.1.6, "Low-Low Set (LLS) Valves."~~ ~~Eight~~ Seven of the S/RVs that provide the safety and ~~relief function are~~ part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS—Operating." ~~The instrumentation associated with the relief valve function and low-low set relief function is discussed in the Bases for LCO 3.3.6.5, "Relief and Low-Low Set (LLS) Instrumentation," and instrumentation for the ADS function is discussed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation."~~

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on ~~high neutron flux (i.e., failure of the direct scram associated with MSIV position)~~ (Ref. 2). For the purpose of the analyses, ~~six~~ of the S/RVs ~~are assumed to operate in the relief mode, and seven in the~~ safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the ~~design basis event~~.

with the highest setpoints 1 (Ref. 1) 12 6 1 overpressure protection 1 most severe pressure transient 1 C

From an overpressure ~~standpoint~~, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 3 discusses additional events that are expected to actuate the S/RVs. Insert ASA 1

1 ,4,5 and 6 1 6

S/RVs satisfy Criterion 3 of the NRC Policy Statement. (Ref. 7) 1 C

5 — ≥25% RTP

LCO

The safety function of ~~seven~~ S/RVs is required to be OPERABLE ~~in the safety mode, and an additional seven S/RVs (other than the seven S/RVs that satisfy the safety function) must be OPERABLE in the relief mode~~. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of ~~seven~~ S/RVs in the safety mode ~~and six S/RVs in the relief mode~~ OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

, with two SRVs in the lowest two lift setpoint groups OPERABLE, 5 12 5 1 5 1 1 when the lift setpoint is exceeded (safety mode) 1 12 5 1 5

Insert LCO 1

The S/RV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 are based on these setpoints, but also include the additional uncertainties of ±1% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

safety 2 1 overpressurization 2 3 5 1 4,5, and 8 1 3 2 involving the safety mode C

(continued)

BASES

LCO (continued)

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded. (1) or unacceptable core thermal margins.

APPLICABILITY (5)

With THERMAL POWER ≥ 25% RTP ~~In MODES 1, 2, and 3~~, the (15) (5) specified number of S~~/~~RVs (1) must be OPERABLE since there ~~may be~~ considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The S~~/~~RVs (1) may be required to provide pressure relief to ~~discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the heat.~~ (2) limit peak reactor pressure.

The requirements for SRVs in MODE 1 with THERMAL POWER < 25% RTP and in MODES 2 and 3 are discussed in LCO 3.4.4, "SRVs — < 25% RTP." (5)

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S~~/~~RV (1) function is not needed during these conditions. C

ACTIONS

A.1

(5)

~~With the safety function of one [required] S/RV inoperable, the remaining OPERABLE S/RVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with two S/RVs inoperable. However, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE S/RVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.~~

~~The 14 day Completion Time to restore the inoperable required S/RVs to OPERABLE status is based on the relief capability of the remaining S/RVs, the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action.~~

(continued)

BASES

ACTIONS (continued)

A.1
~~B.1 and B.2~~ (5)

(1) or core thermal margins may be challenged

With less than the minimum number of required S/RVs (1) OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. ~~If the inoperable required S/RV cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1 or if~~ (1D) (6) ( one ) ~~[two]~~ or more ~~[required]~~ S/RVs are inoperable, the plant (1) must be brought to a MODE in which the LCO does not apply. (5) or other specified condition To achieve this status, ~~the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours~~. THERMAL POWER must be reduced to < 25% RTP within 4 hours (5) The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.~~4~~.1 (3) (5)

This Surveillance demonstrates that the ~~[required]~~ (6) S/RVs (1) will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the S/RV safety function (1) lift settings ~~must be performed during shutdown, since this is a bench test~~ (7) ~~[, and]~~ in accordance with the Inservice Testing Program~~]~~. (6) The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. ~~The S/RV setpoint is ± [3]% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.~~ (5)

~~The [18 month] Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.~~ (5)

~~SR 3.4.4.2~~

~~The [required] relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.~~ (5)

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.4.2 (continued)

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 these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.4.4.3

A manual actuation of each [required] S/RV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine ~~control~~ governor valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the S/RVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is 950 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr]. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the valve fails to actuate due only to the failure of the solenoid but

(continued)

≥ 25% RTP (5)

S/RVs



1C

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.2 (continued) (3) (2) (5)

is capable of opening on overpressure, the safety function of the S/RV is not considered ~~OPERABLE~~ inoperable. (1) (2)

(5) ~~The [18] month on a STAGGERED TEST BASIS Frequency ensures that each solenoid for each S/RV is alternately tested.~~ The (5) (24) month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. (9)). Operating experience has shown that these components usually pass the Surveillance when performed at the (24) month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. (1) (5)

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Section ~~[5.2.2.5.5.3]~~ 15.2.4. (6)
3. FSAR, ~~Section~~ Chapters [15] and 15.F. (6)

<INSERT REFERENCES> (1)

<INSERT B 3.4.4> (5)

## 1 INSERT REFERENCES


4. GE-NE-187-24-0992, "WPPSS Nuclear Project 2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.

5. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.

6. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.

7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

8. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

9. ASME, Boiler and Pressure Vessel Code, Section XI.

INSERT B 3.4.5 * — < 25% RTP (5) (1) ( S/RVs B 3.4.4 1C

B 3.4 REACTOR COOLANT SYSTEM (RCS) 1C

B 3.4.4 Safety/Relief Valves (S/RVs) (1) 1C

BASES

BACKGROUND

(2) A description of the safety/relief valves (SRVs) is provided in the Bases for LCO 3.4.3, "Safety/Relief Valves (SRVs) — ≥ 25% RTP."

~~The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (S/RVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).~~

~~The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.~~ 1C

~~The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston or cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Six of the S/RVs providing the relief function also provide the low-low set relief function specified in LCO 3.6.1.6, "Low-Low Set (LLS) Valves." Eight of the S/RVs that provide the relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS—Operating." The instrumentation associated with the relief valve function and low-low set relief function is discussed in the Bases for LCO 3.3.6.5, "Relief and Low-Low Set (LLS) Instrumentation," and instrumentation for the ADS function is discussed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation."~~

(continued)



* This Bases was added to support proposed Specification 3.4.4. 1C

(5) Insert Page B 3.4-21a

BASES (continued)

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. ~~2~~). For the purpose of the analyses, ~~six~~ four of the S~~/~~RVs with the highest setpoints are assumed to operate in the ~~relief mode, and seven in the~~ safety mode (Ref. 2). The analysis results demonstrate that the design S~~/~~RV capacity is capable of maintaining reactor pressure below the ASME Code limit (Ref. 3) of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the ~~design basis event~~ most severe pressure transient.

INSERT ASA

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. References ~~3~~ 4, 5, and 6 discusses additional events that are expected to actuate the S~~/~~RVs.

S~~/~~RVs — < 25% RTP satisfy Criterion 3 of the NRC Policy Statement (Ref. 7).

LCO

The safety function of ~~seven~~ four S~~/~~RVs is required to be OPERABLE ~~in the safety mode, and an additional seven S/RVs (other than the seven S/RVs that satisfy the safety function) must be OPERABLE in the relief mode~~. The requirements of this LCO are applicable only to the capability of the S~~/~~RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode). In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S~~/~~RVs. The results show that with a minimum of ~~seven~~ four S~~/~~RVs in the safety mode ~~and six S/RVs in the relief mode~~ OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

Since the analysis assumes the overpressurization event is mitigated by SRVs with highest setpoints, any four of the 18 SRVs can be used to meet this LCO.

The S~~/~~RV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions involving the safety mode. The transient evaluations in Reference ~~3~~ 4, 5, and 8 are based on these setpoints, but also include the additional uncertainties of ±~~1~~3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

(continued)



Insert Page B 3.4-21b

1 INSERT ASA

OPERABILITY of SRVs is normally demonstrated during low power operation since an SRV test facility is not available at WNP-2. Therefore, in order to facilitate testing during power operations, an overpressure transient analysis was performed for the bounding accident at 25% RTP. The analysis assumptions were similar to that in Reference 1; closure of all MSIVs followed by a reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position).

BASES

LCO (continued)

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

---

(5) APPLICABILITY

with THERMAL POWER < 25% RTP and MODES

In MODES 1, 2, and 3, the specified number of S/RVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The S/RVs may be required to provide (1) pressure relief to ~~discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the heat.~~ (2) limit peak reactor pressure.

The requirements for SRVs with THERMAL POWER ≥ 25% RTP are discussed in LCO 3.4.3. (5)

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions. (1)

---

ACTIONS

(5)

A.1

With the safety function of one [required] S/RV inoperable, the remaining OPERABLE S/RVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with two S/RVs inoperable. However, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE S/RVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

The 14 day Completion Time to restore the inoperable required S/RVs to OPERABLE status is based on the relief capability of the remaining S/RVs, the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action.

(continued)



Insert Page B 3.4-21d.

INSERT B 3.4.4 (5) — < 25% RTP



BASES

ACTIONS (continued)

(A) (5) Ø.1 and Ø.2

With less than the minimum number of required S/RVs (1) OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. ~~[If the inoperable required S/RV cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1] or if~~ (10) (6) One ~~[two]~~ or more ~~[required]~~ S/RVs are inoperable, the plant (1) must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

(6) (1) This Surveillance demonstrates that the ~~[required]~~ S/RVs will open at the pressures assumed in the safety analysis of Reference 2. (1) The demonstration of the S/RV safety function lift settings ~~must be performed during shutdown, since this is a bench test[, and~~ (1) in accordance with the Inservice Testing Program~~]~~. (6) The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. ~~The S/RV setpoint is ± [3]% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.~~ (5)

(5) ~~The [18 month] Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.~~

(5) ~~SR 3.4.4.2~~

~~The [required] relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.~~

(continued)



Insert Page B 3.4-21e

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.2 (continued) (5)

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 these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

(5) SR 3.4.4.~~3~~ 2

A manual actuation of each ~~[required]~~ (6) S/RV (1) is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine ~~control~~ governor (1) valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure and flow (4) when the S/RVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is ~~950~~ 900 (6) psig (consistent with the (6) ~~the pressure~~ recommendations of ~~ed by~~ the ~~valve manufacturer~~ vendor). Adequate steam flow is represented by ~~[at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr]~~ THERMAL POWER $\geq$ 10% RTP. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to ~~valve installation~~ reactor startup (1). Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure ~~is~~ and flow are (4) reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the valve fails to actuate due only to the failure of the solenoid but

(continued)



Insert Page B 3.4-21a.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.~~4.8~~ (continued)

is capable of opening on overpressure, the safety function of the S/RV is not considered ~~OPERABLE~~ inoperable.

~~The [18] month on a STAGGERED TEST BASIS Frequency ensures that each solenoid for each S/RV is alternately tested.~~ The ~~18~~ 24 month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. ~~1~~ 9). Operating experience has shown that these components usually pass the Surveillance when performed at the ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES


1. ~~ASME, Boiler and Pressure Vessel Code, Section III.~~ WNP-2 Calculation NE-02-94-66, Revision 0, 11/13/95.
2. FSAR, Section ~~[5.2.5.5.3]~~ 5.2.4.
3. ~~FSAR, Section [15]~~.
4. FSAR Chapters 15 and 15.F.
5. GE-NE-187-24-0992, "WPPSS Nuclear Project 2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.
6. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).
8. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
9. ASME, Boiler and Pressure Vessel Code, Section XI.

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.5 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE.

2 This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur detrimental to the safety of the facility or the public.

A limited amount of leakage inside the drywell is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident.

(continued)

1C

BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement. (Ref. 7) 1

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

C

BASES

LCO (continued)

b. Unidentified LEAKAGE

floor drain

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell flow
1 and
~~air~~ monitoring, drywell sump ~~level~~ monitoring, ~~and~~
atmosphere ~~drywell air cooler condensate flow rate monitoring~~
equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

B

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

24 An unidentified LEAKAGE increase of > 2 gpm within the previous ~~4~~ hour period indicates a potential flaw in
5 the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

C

BASES (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE. However, the total LEAKAGE limit would remain unchanged.

B.1 and B.2 24 5

An unidentified LEAKAGE increase of > 2 gpm within a 4 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the leakage rate such that the current rate is less than the "2 gpm increase in the previous 4 hours" limit; either by isolating the source or other possible methods) is to evaluate RCS type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type of piping is very susceptible to IGSCC. 6 24

The 4 hour Completion Time is needed to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.7, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference ~~7~~ 8. In conjunction with alarms and other administrative controls, a ~~8~~ 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. ~~8~~ 9).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes containing Axial Through-Wall Flows," April 1968.
5. NUREG-7~~6~~5/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel piping of Boiling Water Reactors," October 1975.
6. FSAR, Section ~~[~~5.2.5.5.3~~]~~.
~~7~~ 8. Regulatory Guide 1.45, May 1973.
~~8~~ 9. Generic Letter 88-01, Supplement 1, February 1992.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

1C

1A

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

### B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

RCS PIVs are defined as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB). The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE."

3

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following 1 ~~typically~~ connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System;

(continued)

BASES

BACKGROUND (continued)

c. High Pressure Core Spray System; and

d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 6.

APPLICABLE SAFETY ANALYSES

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment. RCS PIV leakage satisfies Criterion 2 of the NRC Policy Statement. (Ref. 7) 1

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 4).

1 Reference ~~0~~ 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

(continued)

1 ⚠

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR flowpath are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR shutdown cooling mode of operation.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate, affected RCS PIV flow paths. As such, 3 a Note has been provided that allows separate Condition entry for each affected RCS PIV flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system OPERABILITY, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

A.1 and A.2 5

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed

(continued)

1C

BASES

ACTIONS

A.1 and A.2 (continued)

manual, deactivated, automatic, or check valve within 4 hours. Required Action A.1 ~~and Required Action A.2 are~~ is modified by a Note stating that ~~the~~ a check valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB ~~for the high pressure portion of the system.~~

5 1B 11

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseat the leaking PIVs are taken. The 4 hours allows time for these actions and restricts the time of operation with leaking valves, and

~~Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing another valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit~~ considers ~~the time required to complete the Required Action,~~ the low probability of a second valve failing during this time period, and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. ~~2~~ 8).

5 1

B.1 and B.2

If leakage cannot be reduced or the system isolated, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

1C

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm

(continued)

A

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1 (continued)

per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

2 As stated in the LCO Section of the Bases, the test pressure may be at a lower pressure than the maximum pressure differential (at the RCS maximum pressure of 1035 psig) provided the observed leakage rate is adjusted in accordance with Reference 4. The actual test pressure shall be ≥ 935 psig.

The 18 month 5 Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified only by a Note that states the leakage Surveillance is ~~not~~ required to be performed in MODE 3 1 and 2 5 5. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

B

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. NUREG-0677, "The Probability of Intersystem LOCA: Impact due to Leak Testing and Operational Changes," May 1980. 2
6. ~~FSAR, Section [ ]~~ Licensee Controlled Specifications Manual. 6
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). 1
~~7~~ 8. NEDC-31339, "BWR Owners Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," November 1986. 2

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. The Bases for LCO 3.4.5, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of two ~~or three~~ independently monitored variables, such as sump ~~level~~ changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

drain flow

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump has transmitters that supply ~~level~~ indications in the main control room.

flow

Reactor Building

The drywell floor drain sump gravity drains to a reactor building floor drain sump.

piping to the reactor building floor drain sump

ies flow

Insert Background

~~The floor drain sump level indicators have switches that start and stop the sump pumps when required. A timer starts each time the sump is pumped down to the low level setpoint.~~

(continued)

C

BASES

BACKGROUND (continued)

1

~~If the sump fills to the high level setpoint before the timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit. A second timer starts when the sump pumps start on high level. Should this timer run out before the sump level reaches the low level setpoint, an alarm is sounded in the control room indicating a LEAKAGE rate into the sump in excess of a preset limit. A flow indicator in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room.~~

1 atmosphere (particulate and gaseous) 2

The drywell ~~air~~ monitoring systems continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring systems are not capable of quantifying leakage rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour (Ref. 3) 1. Larger changes in LEAKAGE rates are detected in proportionally shorter times ~~(Ref. 3)~~. 1

10

~~Condensate from four of the six drywell coolers is routed to the drywell floor drain sump and is monitored by a flow transmitter that provides indication and alarms in the control room. This drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS unidentified LEAKAGE.~~

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 4 and 5). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room.

A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement. (Ref. 7) 1

LCO

The drywell floor drain sump (flow 1) monitoring system is required to quantify the unidentified LEAKAGE from the RCS. ~~Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE.~~ 1 The other monitoring systems (particulate or gaseous) 2 provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1

With the drywell floor drain sump (flow 1) monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell atmospheric activity monitor ~~and the drywell air cooler condensate flow rate monitor~~ 10 will provide indications of changes in leakage.

5

With the drywell floor drain sump (flow 1) monitoring system inoperable, but with RCS unidentified and total LEAKAGE ~~being determined every~~ 12 8 hours (SR 3.4.5.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available. Required Action A.1 is modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the drywell floor drain sump (flow 1) monitoring system

(continued)

10

BASES

ACTIONS

A.1 (continued)

is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

2

(i.e., the required drywell atmospheric monitoring system)

B.1 and B.2

With both gaseous and particulate drywell atmospheric monitoring channels inoperable, grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the required monitors. ~~[Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation since at least one other form of drywell leakage detection (i.e., air cooler condensate flow rate monitor) is available.]~~

6

10

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for restoration recognizes that at least one other form of leakage detection is available.

The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate primary containment atmospheric monitoring channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

~~[C.1~~

~~With the required drywell air cooler condensate flow rate monitoring system inoperable, SR 3.4.7.1 is performed every 8 hours to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.4.7.1. The 8 hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leakage detection are available. However, this Required Action is modified by a Note that allows this action to be not applicable if the required drywell atmospheric monitoring system is inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.]~~

10

5

(continued)

1A

BASES

ACTIONS (continued)

D.1 and D.2

With both the gaseous and particulate drywell atmospheric monitor channels and the drywell air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the drywell floor drain sump monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate primary containment atmospheric monitoring channels and air cooler condensate flow rate are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

5 10

5 C ~~E~~.1 and ~~E~~.2

2 and or 5

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

5 D ~~F~~.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

5 <INSERT SR>

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

1A

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.7.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.7.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of ~~[~~18~~]~~ months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable. 6

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section ~~[~~5.2.5~~.~~ ~~[~~~~]~~. 5.5 6
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968. 2
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975. 2
6. FSAR, Section ~~[~~5.2.5.5.~~3]~~. 6
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132). 1

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.8 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure, in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

14

TSTF-03 changes Not Shown

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the FSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB

(continued)

1A

BASES

**APPLICABLE SAFETY ANALYSES (continued)**

outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100.

4 The limit~~s~~ on specific activity ~~are~~ is a value~~s~~ from a parametric evaluation of typical site locations. ~~These~~ This limit~~s~~ ~~are~~ is conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement (Ref. 3). 1

**LCO**

The specific iodine activity is limited to ≤ ~~[~~0.2~~]~~ µCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits. 6

**APPLICABILITY**

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

**ACTIONS**

A note to the Required Action~~s~~ of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to

12 move to Insert A.1 and A.2, next page

(continued)

BASES

ACTIONS (continued)

restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

Move to Insert A.1 and A.2, this page

12

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

INSERT A.1 AND A.2

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ ~~[0.2]~~ μCi/gm within 48 hours, or if at any time it is > ~~[4.0]~~ μCi/gm, it must be determined at least every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

6

Alternately, the plant can be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for bringing the plant to MODES 3 and 4 are reasonable, based on

(continued)

1C

BASES

ACTIONS

B.1, B.2.1, B.2.2.1, and B.2.2.2 (continued)

operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

1C

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 100.11, ~~1973~~. 2
2. FSAR, Section ~~15.1.40~~ 15.6.4. 6

1

3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

### B 3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown

BASES

**BACKGROUND**

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to ≤ 200°F. ~~This decay heat removal is~~ the decay heat must be removed for in preparation for performing Cold Shutdown refueling or maintenance operations, or ~~for~~ ~~keeping~~ maintaining the reactor in the Hot Shutdown condition. (2)

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. (a) (1) Each loop consists of a motor driven pump, ~~two~~ heat exchanger~~s in series~~, and associated piping and valves. (1) Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. ~~separate feedwater lines or to the reactor via the LPCI injection path.~~ The RHR heat exchangers transfer heat to the Standby Service Water System (LCO 3.7.1, "[Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)]"). (6)

**APPLICABLE SAFETY ANALYSES**

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. (5) ~~Although~~ The RHR Shutdown Cooling System ~~does not~~ meets ~~a specific~~ Criterion (4) of the NRC Policy Statement (Ref. 1). ~~It was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.~~ (13)

**LCO**

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, ~~two~~ one heat exchanger~~s in series~~, and the (1)

(continued)

 C

BASES

LCO (continued)

associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR cut in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR Shutdown Cooling System ~~may~~ must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation. 1 4

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, 1 1

(continued)

C

BASES

APPLICABILITY (continued)

"ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

C

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

A Note to the ACTIONS excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the redundancy of the OPERABLE subsystems, the low pressure at which the plant is operating, the low probability of an event occurring during operation in this condition, and the availability of alternate methods of decay heat removal capability.

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

<u>A.1, A.2, and A.3</u>

1

With one ~~required~~ RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single

(continued)

BASES

ACTIONS

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

failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the ~~Spent~~ Fuel Pool Cooling System, ~~or~~ the Reactor Water Cleanup System. Condensate/Main Steam

(by itself, or using feed and bleed in combination with the Control Rod Drive System or Condensate System), and a combination of an ECCS pump and a safety/relief valve.

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

B.1, B.2, and B.3

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable

(continued)

1C

BASES

ACTIONS

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

separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

1C

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES

~~None~~

1 1. Final Policy Statement on Technical Specifications Development, July 22, 1993 (58 FR 39132).

C

# B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown

C

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant at ≤ 200°F. ~~This decay heat removal is~~ the decay heat must be removed for in preparation for performing refueling ~~or~~ maintenance operations, or ~~for~~ ~~keeping~~ maintaining the reactor in the Cold Shutdown condition.

B 2 2

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, ~~two~~ heat exchangers ~~in series~~, and associated piping and valves. Both loops have a common suction from the same recirculation loop the associated recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via ~~separate feedwater lines or to the reactor via the LPCI injection path~~. The RHR heat exchangers transfer heat to the Standby Service Water (SW) System.

a 1 1 1

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. ~~Although~~ the RHR Shutdown Cooling System ~~does not~~ meet ~~a specific~~ criterion of the NRC Policy Statement (Ref. 1). ~~it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.~~

13 5 4

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, ~~two~~ one heat exchanger ~~in series~~, one SW pump providing cooling to the heat exchanger and the associated piping and valves. Each shutdown cooling

1 1

(continued)

C

BASES

LCO (continued)

subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain and reduce the reactor coolant temperature as required. ~~However,~~ To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

2 Shutdown Cooling 4 must be OPERABLE and shall

In MODE 4, the RHR System ~~may~~ be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 200°F. Otherwise, a recirculation pump is required to be in operation.

1

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation. 1

(continued)

1C

BASES

APPLICABILITY (continued)

The requirements for decay heat removal in MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level." 1C

ACTIONS

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

A.1

With one of the two ~~required~~ (1) RHR shutdown cooling subsystems inoperable except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

(continued)

BASES

ACTIONS

A.1 (continued)

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or ~~contributing to~~ the alternate method capability. Alternate methods that can be used include (but are not limited to) ~~the Spent Fuel Pool Cooling System or~~ the Reactor Water Cleanup System.

(by itself, or using feed and bleed in combination with the Control Rod Drive System or Condensate System), and a combination of an ECCS pump and a safety/relief valve.

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling system or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1 (continued)

sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

REFERENCES

None.

1

1. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).

1 C

# B 3.4 REACTOR COOLANT SYSTEM (RCS)

## B 3.4.11 RCS Pressure and Temperature (P/T) Limits

1 C

BASES

---

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

S Specification

and criticality also limits

The ~~PTLR~~ contains P/T limit curves ~~for~~ heatup, cooldown, ~~and~~ inservice leak and hydrostatic testing, and ~~data for~~ the maximum rate of change of reactor coolant temperature. ~~The heatup curve provides limits for both heatup and criticality.~~ 1 C

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The actual shift in the $RT_{NDT}$ of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and 10 CFR 50, Appendix H (Ref. 4). The operating P/T limit curves will be adjusted,

(continued)

---

C

BASES

1

BACKGROUND (continued)

as necessary, based on the evaluation findings and the recommendations of Reference 5.

linear elastic fracture mechanics (LEFM) analyses

The P/T limit curves are composite curves established by superimposing limits derived from ~~stress analyses~~ of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

1

However, only the more restrictive of the two curves is used.

The criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing.

P/T

1

C

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. References 7 ~~establishes the methodology for determining the P/T limits.~~ Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits

C

5

and 8 approved the curves and limits required by this Specification.

(continued)

 1C

BASES

---

APPLICABLE SAFETY ANALYSES (continued)

are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement (Ref. 9). 1 1C

---

LCO

The elements of this LCO are:

a. RCS pressure and temperature, and heatup and ~~or~~ cooldown rates are ≤100°F in any 1 hour period are within the limits specified in ~~the PTLR~~ Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 during RCS heatup, cooldown, and inservice leak and hydrostatic testing, and the RCS temperature change during inservice leak and hydrostatic testing is ≤20°F in any 1 hour period when the RCS pressure and RCS temperature are not within the limits of Figure 3.4.11-2; 1C

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ~~within the limit of the PTLR~~ ≤145°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow; 1C

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel ~~meets the limit of the PTLR~~ is ≤50°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow; 1C

d. RCS pressure and temperature are within the ~~criticality~~ limits specified in ~~the PTLR~~ Figure 3.4.11-3, prior to achieving criticality; and 1 1C

e. The reactor vessel flange and the head flange temperatures are ~~within the limits of the PTLR~~ ≥80°F when tensioning the reactor vessel head bolting studs. 1C

5

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and ~~are~~ used as inputs for calculating the heatup, cooldown, and inservice leak and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by

(continued)

---

BASES

LCO (continued)

thermal gradients and also ensures the validity of the P/T limit curves.

LEFM 1

Violation of the limits places the reactor vessel outside of the bounds of the ~~stress~~ analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

3 c. The existence~~s~~, size~~s~~, and orientation~~s~~ of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by ~~stress~~ LEFM analyses. 1

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with

(continued)

1C

BASES

ACTIONS

A.1 and A.2 (continued)

1

pre-analyzed transients ~~in the stress analyses~~, new analyses, or inspection of the components.

2

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by bringing the plant to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

C

BASES

ACTIONS (continued)

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by ~~stress~~ analyses. The Required Action must be initiated without delay and continued until the limits are restored.

LEFM

1

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

2

INSERT C.1 AND C.2

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

C

C

Verification that operation is within PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction of minor deviations.

5

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

This SR has been modified by a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

1

The limits of Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 are met when operation is to the right of the applicable limit curves

C

(continued)

The limits of Figure 3.4.11-3 are met when Operation is to the right of the limit curve.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.11.3 and SR 3.4.11.4

Differential temperatures within the applicable PTLR limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 6) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.11.3 and SR 3.4.11.4 have ~~has~~ been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during a recirculation pump startup since this is when the stresses occur ~~with reactor steam dome pressure ≥ 25 psig~~. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

INSERT SR 3.4.11.5 AND SR 3.4.11.6

SR 3.4.11.5, SR 3.4.11.6, and SR 3.4.11.7

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits

(continued)

(5) INSERT SR 3.4.11.5 and SR 3.4.11.6 10

SR 3.4.11.5 and SR 3.4.11.6 10

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation. 10

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.6 is to compare the temperatures of the operating recirculation loop and the idle loop. 10

Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels > 25% of RTP and with single loop flow rate > 10% of rated loop flow. Therefore, SR 3.4.11.5 and SR 3.4.11.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.11.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop can not be introduced into the remainder of the Reactor Coolant System. 10

C

BASES

SURVEILLANCE REQUIREMENTS

(5)

SR 3.4.11.~~6~~ 7, SR 3.4.11.~~7~~ 8 and SR 3.4.11.~~8~~ 9 (continued) C

during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ ~~80~~ (90) (5) °F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the limits specified ~~in the PTLR~~. (5) C

(2) INSERT SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures. C

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

(1)

9. ~~7~~. ~~NEDO-21778-A, December 1978.~~
10. ~~8~~. FSAR, Section ~~15.1.28~~ 4.4. (6) C

(1) Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).



7. Letter from D.G. Eisenhut (NRC) to D.W. Mazur (WPPSS), "Issuance of Facility Operating Licence NPF-21 — WPPSS Nuclear Project No. 2," dated December 20, 1983.

8. Letter from J.W. Clifford (NRC) to J.V. Parrish (WPPSS), "Issuance of Amendment 137 for WPPSS Nuclear Project No. 2," dated May 2, 1995.

C

INSERT SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9

2

SR 3.4.11.7 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.11.8 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 90°F in MODE 4. SR 3.4.11.9 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature ≤ 100°F in MODE 4. The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the specified limits.

## B 3.4 REACTOR COOLANT SYSTEM (RCS)

### B 3.4.12 Reactor Steam Dome Pressure

BASES

| | |
|---|---|
| BACKGROUND | 2 The reactor steam dome pressure is an assumed initial condition of Design Basis Accidents (DBAs) and transients ~~and is also~~ an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria. and is also |
| APPLICABLE SAFETY ANALYSES | The reactor steam dome pressure of ≤ ~~[1045]~~ 1035 6 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of DBAs and transients used to determine the limits for fuel cladding integrity (MCPR) 1 (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% fuel 2 cladding plastic strain (see Bases for LCO 3.2.1, "~~AVERAGE PLANAR~~ LINEAR HEAT GENERATION RATE (APLHGR)"). 3 11 e 3<br>1 Insert Applicable Safety Analyses<br>Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement (Ref. 3). 7 |
| LCO | 6 1035 The specified reactor steam dome pressure limit of ≤ ~~[1045]~~ psig ensures the plant is operated within the assumptions of the ~~transient analyses~~. Operation above the limit may result in a ~~transient~~ response more severe than analyzed. 1 reactor overpressure analyses |
| APPLICABILITY | In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these |

(continued)

C

BASES

APPLICABILITY (continued)

MODES, the reactor may be generating significant steam, and ~~the DBAs and transients are bounding~~ 1 events that may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal. ~~If the operator is unable to restore the reactor steam dome pressure to below the limit, then the reactor should be brought to MODE 3 to be within the assumptions of the transient analyses.~~ 4

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 1035 6

C

Verification that reactor steam dome pressure is ≤ ~~1045~~ psig ensures that the initial conditions of the ~~DBAs and transients are~~ 1 vessel overpressure protection analyses is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

C

C

BASES (continued)

REFERENCES

1. FSAR, Section ~~1~~5.2.2.~~X~~. 6
2. FSAR, ~~Section~~ Chapters 15~~X~~. and 15.F

1

3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

# JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
## BASES SECTION 3.4 - REACTOR COOLANT SYSTEMS

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. Editorial change made for enhanced clarity or to be consistent with similar statements in other places in the Bases.

3. Typographical/grammatical error corrected.

4. Changes have been made to more closely match the LCO requirements.

5. Changes have been made to reflect those changes made to the Specification. The following requirements have been renumbered, where applicable, to reflect the changes.

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

7. The Specification deals with the flow control valves and there is no reason to reference the jet pumps. Therefore, the reference to jet pumps has been deleted. This concept (not referencing in a "subcomponent" Bases the other "subcomponents" of the associated system) is consistent with other sections of the ITS Bases.

8. The word "may" has been added since a change in the described relationship may be due to other factors. C

9. This statement has been deleted since it is misleading; an increase in flow could be indicative of other problems.

10. The bracketed requirement/information has been deleted because it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect the changes.

11. Not used. C

12. The Note description has been moved to the proper location, consistent with the Writer's Guide conventions. This new location was where the Note, added to Revision 1 by BWOG-2, C.3, was supposed to have been added; however, it was inadvertently added in the wrong location in the typed version of Revision 1.

13. The proper Final Policy Statement criterion has been used. The current wording was developed prior to the issuance of the Final Policy Statement, which uses criterion 4 for the current words of the NUREG.

14. Generic change TSTF-03 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

VOLUME 10

BASES

LCO (continued)

injection/spray subsystems are defined as the LPCS System and the three LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

3 Insert LCO

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, the ADS function is not required when pressure is ≤ 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS—Shutdown."

ACTIONS

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this ~~Condition, the~~ remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 1 ~~12~~ 13) that evaluated the impact on ECCS availability by assuming that various components and subsystems were taken

(continued)

BASES

ACTIONS

A.1 (continued)

out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

Immediately 4

If the HPCS System is inoperable, and the RCIC System is verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate 4 Verification of RCIC OPERABILITY ~~within 1 hour~~ 4 1B is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other information 3 to determine if RCIC is out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be Immediately 4 verified and RCIC is required to be OPERABLE, Condition D must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on the results of a reliability study (Ref. 12) and has been found to be acceptable through operating experience. 13 1 1C

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this condition, the 3 1A remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis

(continued)

BASES

ACTIONS

C.1 (continued)

LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference ~~12~~. 13 1

D.1 and D.2

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

E.1

The LCO requires ~~eight~~ six 4 ADS valves to be OPERABLE to provide the ADS function. Reference ~~12~~ 14 1 contains the results of an analysis that evaluated the effect of ~~one~~ two 1 ADS valves being out of service. ~~Per~~ this analysis showed that assuming a failure of the HPCS System 1 5, operation of only ~~seven~~ five 1 ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. ~~12~~ 13 1) and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one required 3 inoperable ADS valves, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure (ADS) and low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. ~~12~~ 13) and has been found to be acceptable through operating experience. 1 | C

G.1 and G.2

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more Required ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. 3

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

The Frequency of ~~18~~ 24 months on a required STAGGERED TEST BASIS ensures that both ADS trip system solenoids for each ADS valve are alternately tested. The Frequency is based on the need to perform this Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the ~~18~~ 24 month Frequency~~, which is based on the refueling cycle~~. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section {6.3.2.2.3}.
2. FSAR, Section {6.3.2.2.4}.
3. FSAR, Section {6.3.2.2.1}.
4. FSAR, Section {6.3.2.2.2}.
5. FSAR, Section {15.~~2~~.~~8~~}.
6. FSAR, Section {15.6.4}.
7. FSAR, Section {15.6.5}.
8. 10 CFR 50, Appendix K.
9. FSAR, Section {6.3.3}.
10. 10 CFR 50.46.
11. FSAR, Section {6.3.3.3}.
~~12~~ 13. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
~~13~~ 14. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR Loss-of-Coolant Accident Analysis," Revision 2, July 1993. ~~FSAR, Section [6.3.3.7.8].~~
~~14. FSAR, Section [7.3.1.1.1.4.2].~~
12. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

ACTIONS

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

MOVE TO PREVIOUS PAGE

3

The 4 hour Completion Time to restore at least one ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

18 ft 6 inches

5

The minimum water level of ~~[12.67 ft]~~ required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST.

1

(135,000 gallons, consistent with the CST volume requirement described below)

When the suppression pool level is < ~~[12.67 ft]~~, the HPCS System is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is ≥ ~~[12.67 ft]~~ or the HPCS System is aligned to take suction from the CST and the CST contains ≥ ~~[170,000]~~ gallons of water, equivalent to ~~18 ft~~, ensures that the HPCS System can supply makeup water to the RPV.

5

18 ft 6 inches

5

135,000

a level of 13.25 ft in a single CST or 7.6 ft in each CST

1

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.5 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

C

(continued)

BASES

ACTIONS (continued)

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 ~~are~~ be taken. 10

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable (except for ~~purge valve or~~ secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits), 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, 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.

2 C

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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, drywell, and steam tunnel 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, drywell, and steam tunnel," is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside the primary containment, drywell, or steam tunnel, the specified time period of "prior to entering MODE 2 or 3 from 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.

4 if primary containment was de-inerted while in MODE 4,

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

Required Action A.2 is modified by a Note that 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. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

1

B.1

With one or more penetration flow paths with two PCIVs inoperable, 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.

4 except for secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits

C

(continued)

BASES (25) <TSTF-30 Changes not shown>

ACTIONS

B.1 (continued)

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

C.1 and C.2

(4) except for secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits

When one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. 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]~~ 4 hours. The ~~[4]~~ 4 hour Completion Time is reasonable (3) considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. 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. The Completion Time of once per 31 days ~~for verifying that each affected penetration is isolated~~ is appropriate because the ~~valves~~ devices are operated under administrative controls and the probability of their misalignment is low. (11) <INSERT ACTIONS C.1 and C.2>

(12) for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines

(12) The Completion Time of 12 hours is reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument.

(1) 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.

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 PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written

(4) "for isolation devices outside primary containment"

(C)

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

specifically to address those penetrations with a single PCIV.

isolation devices

13

Required Action C.2 is modified by a Note that applies to ~~valves and blind flanges~~ located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

4

MSIV leakage rate, or hydrostatically tested lines leakage rate

14

may

C

D.1

14.

be

(8 hours for main steam lines)

4

3

6

With the secondary containment bypass leakage rate, not within limit, the assumptions of the safety analysis are not met. Therefore, the leakage must be restored to within limit within 4 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 isolation ed penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time 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.

4

4

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

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. 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

(continued)



4

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.

BASES

SURVEILLANCE REQUIREMENTS

4

~~SR 3.6.1.3.12 (continued)~~

~~concerns are not present, thus the purge valves can be fully open. The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.~~

REFERENCES

1. FSAR, Chapter ~~(15)~~ 6.2 3 Section 15.2.4 1C
~~2.~~ 3 1 FSAR, Section [6.2]. 1
~~3.~~ 1 2 FSAR, ~~[Table 6.2-44]~~.
~~4. 10 CFR 50, Appendix J.~~ 4

4. Licensee Controlled Specifications Manual 1B

Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). 1

Changes per TSTF-30 not adopted

25

4 INSERT B 3.6.1.7 ACTION C.1

C.1

With one or more vacuum breakers with two disks not closed, this allows communication between the drywell and suppression chamber, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, one open vacuum breaker disk must be closed. A short time is allowed to close one of the vacuum breaker disks due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breaker disks are closed is to verify that a differential pressure of ≥ 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test. 1C

BASES

ACTIONS

A.1 (continued)

cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

13

If the Required Action and associated ~~required~~ Completion Time of Condition A cannot be met or if two RHR suppression pool cooling subsystems are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. C

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the [SSW] System and [UHS] are required to be OPERABLE to support OPERABILITY of ~~the~~ equipment serviced by the [SSW] System and [UHS] ~~, and are~~ that is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the [SSW] System and [UHS] are determined by the systems they support. <INSERT APP>

ACTIONS

A.1

<INSERT ACTION A.1>

~~If one or more cooling towers have one fan inoperable (i.e., up to one fan per cooling tower inoperable), action must be taken to restore the inoperable cooling tower fan(s) to OPERABLE status within 7 days.~~

~~The 7 day Completion Time is reasonable, based on the low probability of an accident occurring during the 7 days that one cooling tower fan is inoperable in one or more cooling towers, the number of available systems, and the time required to complete the Required Action.~~

B.1

If one [SSW] subsystem is inoperable ~~(for reasons other than Condition A)~~, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE [SSW] subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE [SSW] subsystem could result in loss of [SSW] function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable [SSW] subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
BASES SECTION 3.7 - PLANT SYSTEMS

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

2. Editorial change made for enhanced clarity or to be consistent with similar statements in other places in the Bases.

3. 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.

4. This statement has been deleted since it does not apply to the SW System; it discusses how some supported systems are initiated. This discussion is more appropriately located in the supported systems Bases (which it is).

5. The Applicability section of the Bases for LCO 3.7.1, SW System and UHS, and LCO 3.7.4, Control Room AC System, has been revised to add clarification regarding OPERABILITY requirements for the SW System and UHS during MODES 4 and 5.

6. Changes have been made to reflect those changes made to the Specification. The following requirements have been renumbered, where applicable, to reflect the changes.

7. Not used. | C

8. Changes have been made to more closely match the LCO requirements.

9. Typographical/grammatical error corrected.

10. These words have been added to clarify that the boundary is not necessarily required to be leak-tight, but is required to meet the leak tightness requirements of SR 3.7.3.4 (i.e., leakage can occur as long as a 0.125 inch pressure is maintained in the control room). Also, an allowance to open control room access doors for entry and exit has been added since the design of the boundary only has one door.

11. This LCO is needed to ensure the MCPR limit is not exceeded. The cladding 1% plastic strain limit is an LHGR concern, not a MCPR concern. Therefore, this statement has been deleted. In addition, the statement that refers to the APHLGR Bases has also been deleted since this LCO is only concerned with MCPR.

BASES

LCO (continued) 15 1

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

for Division 1 and 2 DGs and 18 seconds for Division 3 DG. The DG-3 18 second start-time includes the Loss of Voltage-Time Delay Function specified in LCO 3.3.8.1

3 Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. INSERT B 3.8.1 LCO-B

APPLICABILITY

8 The AC sources ~~and sequencers~~ are required to be OPERABLE in MODES 1, 2, and 3 to ensure that: 1 C

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS

(continued)

BASES

ACTIONS

A.3 (continued)

{8} ~~Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable.~~ With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

The Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The ~~third~~ second {8} Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met. C

Similar to {9} ~~As in~~ Required Action A.2, the Completion Time of Required Action A.3 {3} allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

BASES

ACTIONS

B.2 (continued)

hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E or G of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

9 10 3

4

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the ~~plant corrective action program~~ Problem Evaluation Request Process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

1 10 4

According to Generic Letter 84-15 (Ref. 2), [24] hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

1C

(continued)

BASES

ACTIONS (continued)

B.4

According to Regulatory Guide 1.93 (Ref. 8 9 1), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the 3 low probability of a 3 a DBA occurring during this period.

C

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

C

9 Similar to ~~As in~~ Required Action B.2, the Completion Time of Required Action B.4 3 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of

(continued)

BASES

ACTIONS

E.1 (continued)

9 1

According to Regulatory Guide 1.93 (Ref. 8), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with the other Division 1 or 2 DG remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent—an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, Division 3 systems HPCS could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

C

3

6

F.1

The sequencer(s) is an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer(s) is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus.]. Therefore, loss of an [ESF bus's sequencer] affects every major ESF system in the [division]. The [12] hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident requiring sequencer OPERABILITY occurring during periods when the sequencer is inoperable is minimal.

This Condition is preceded by a Note that allows the Condition to be deleted if the plant design is such that any sequencer failure mode only affects the ability of the associated DG to power its respective safety loads under any conditions. Implicit in this Note is the concept that the Condition must be retained if any sequencer failure mode results in the inability to start all or part of the safety

(continued)

BASES

ACTIONS

F.1 (continued)

loads when required, regardless of power availability, or results in overloading the offsite power circuit to a safety bus during an event thereby causing its failure. Also implicit in the Note is the concept that the Condition is not applicable to any Division that does not have a sequencer [Division 3 does not normally have a sequencer in the circuitry].

(6)

(6) F G.1 and G.2

If the inoperable AC electrical power sources ~~and sequencers~~ cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to 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.

(6)

(6) G H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 11 8). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are consistent ~~in accordance~~ with the recommendations of Regulatory Guide 1.9 (Ref. 12 3), Regulatory Guide 1.108 (Ref. 13 9), and Regulatory Guide 1.137 (Ref. 14 10).

(1) (1) (1) (1) C

(continued)

(1)

For Division 1 and 2 DGs,

BASES (1) <INSERT B 3.8.1 SR-A>

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 [3740] V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. (1) The specified maximum steady state output voltage of ~~[4576]~~ 4400 (4) 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 Safety Guide 9 (Ref. 5) and Regulatory Guide 1.9 (Ref. ~~3~~ 12). (1)

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 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note ~~2~~ (1)-(B) for SR 3.8.1.2) to indicate that all DG starts for these

(continued)

1 INSERT B 3.8.1 SR-A

depends upon whether or not the DG is tied to its respective 4.16 kV ESF bus. If the SR does not require the DG to be tied to its bus, then the minimum steady state output voltage is 3910 V, which is the minimum voltage necessary to meet the DG breaker closure interlock. If the SR requires the DG to be tied to its respective 4.16 kV ESF bus, then the minimum steady state output voltage is 3740 V. Studies have shown that with design basis maximum loading on the Class 1E distribution system, the Class 1E loads at all voltage levels (4160 V, 480 V, and 120 V) will have sufficient voltage at their terminals to meet or exceed their minimum voltage requirements when the voltage on the Class 1E 4.16 kV ESF bus is 3696 V or higher (Ref. 15). The specified value of 3740 V provides a conservative allowance for calculational uncertainties. For the Division 3 DG, minimum steady state output voltage is 3740 V. The basis for this value is the same as for the Division 1 and 2 DGs 3740 V value. 1C

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

[In order to reduce stress and wear on diesel engines, the ~~some~~ manufacturers recommend that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such procedures are recommended by the manufacturer.]

to SR 3.8.1.2

SR 3.8.1.7 requires that, at a 184 day Frequency, 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. 10). The 10 second start requirement may not be applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. ~~Since SR 3.8.1.7 does require a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.~~

Brackets added per TSTF-37

The ~~normal~~ 31 day Frequency for SR 3.8.1.2 [~~(see Table 3.8.1-1, "Diesel Generator Test Schedule")~~] is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting ~~greater than or equal to the~~

(continued)



a load approximately equivalent to that corresponding to the continuous rating.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

1 ~~equivalent of the maximum expected accident loads~~. 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 (4) between [0.8 lagging] and [1.0]. The [0.8] value is the design rating of the machine, ~~while~~ [1.0] is an operational ~~limitation [to ensure circulating currents are minimized]~~. 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.

when running synchronized with the grid

. The

Since the generator is rated at a particular KVA at 0.8 power factor,

INSERT B 3.8.1 SR-B

1

4

Brackets added per TSTF-37

The ~~[normal]~~ 31 day Frequency for this Surveillance ~~(see Table 3.8.1-1)~~ is consistent with Regulatory Guide 1.9 (Ref. 3).

12 – 1

6

1C

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 ~~and engine mounted tank~~ is at or above the

6

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

1

For DGs 1 and 2, the required fuel oil level supports approximately 3.5 hours of operation at 110% of the continuous rated load. For DG-3, the required fuel oil level supports approximately 7 hours of operation at continuous rated load. The amount above the minimum 1 hour requirement helps to support the 7 day fuel oil supply.

the low level alarm is annunciated 1

level at which ~~fuel oil is automatically added~~. 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 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 ~~and engine mounted~~ tanks once every [31] days eliminates the necessary environment for bacterial survival. This is the 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. 14). 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.

4 6 3 1 9 4 15 14 1 1C

SR 3.8.1.6

automatically E

This Surveillance demonstrates that each required fuel oil transfer pump 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 the fuel oil transfer pump is OPERABLE, the fuel oil piping

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

4

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. ~~12~~ 17) ~~; 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~~.

17 1 4 4 1C

~~SR 3.8.1.7~~ 3

~~See SR 3.8.1.2.~~

SR 3.8.1.8

Division 1 and 2 1 es (SM-7 and SM-8) 1 backup 1 startup 1 Division 1 and 2 1

Transfer of ~~each~~ Division 1 and 2 4.16 kV ESF buses (SM-7 and SM-8) power supply from the ~~normal~~ startup offsite circuit to the ~~alternate~~ backup offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the Division 1 and 2 shutdown loads. The ~~[18]~~ 24 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]~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

24 4 4 24 4

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

SR 3.8.1.8 (continued)

safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined ~~voltage and~~ frequency and while maintaining a specified margin to the overspeed trip. The load referenced for DG 11 and 2 is the ~~1200~~ 1280 kW ~~low pressure core spray~~ Standby service water pump~~; for DG 12, the 550 kW residual heat removal (RHR) pump~~, and for DG 13 the ~~2180~~ 2380 kW HPCS pump. ~~The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG.~~ 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.

~~As required by IEEE-308 (Ref. 13)~~ Consistent with Regulatory Guide 1.9 (Ref. 12), the load rejection test is acceptable if the ~~increase in~~ diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between ~~synchronous~~ nominal speed and the overspeed trip setpoint, or ~~15% above synchronous~~ 115% of nominal speed, whichever is lower. For all the DGs, this corresponds to 66.75 Hz, which is the nominal speed plus 75% of the difference between nominal speed the overspeed trip setpoint. ~~For the Grand Gulf Nuclear Station these values are the same.~~

~~The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of the 5 second load~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

9 safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the 8 largest single load without exceeding predetermined ~~voltage and~~ frequency and while maintaining a specified margin to the overspeed trip. The load referenced for DG 1~~1~~ and 2 is the ~~1200~~ 1280 kW ~~low pressure core spray~~ Standby service water pump ~~for DG 12, the 550 kW residual heat removal (RHR) pump~~, and for DG ~~1~~3 the ~~2180~~ 2380 kW HPCS pump. ~~The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG.~~ 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.

~~As required by IEEE-308 (Ref. 13)~~ Consistent with Regulatory Guide 1.9 (Ref. 12), the load rejection test is acceptable if the ~~increase in~~ diesel speed does not exceed the nominal (synchronus) speed plus 75% of the difference between ~~synchronous~~ nominal speed and the overspeed trip setpoint, or ~~15% above synchronous~~ 115% of nominal speed, whichever is lower. ~~For the Grand Gulf Nuclear Station these values are the same.~~ For all the DGs, this corresponds to 66.75 Hz, which is the nominal speed plus 75% of the difference between nominal speed the overspeed trip setpoint.

~~The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of the 5 second load~~ 8

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

takes into consideration the plant conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths.

~~sequence interval associated with sequencing of this largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection.~~ The ~~[18]~~ 24 month~~s~~ Frequency ~~is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).~~

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 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 ~~using a power factor ≤ [0.9]~~ 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 DG-1, ≤ 0.86 for DG-2, and ≤ 0.92 for DG-3. Th~~is~~ese power factors ~~is chosen~~ are ~~to be~~ representative of the actual ~~design basis~~ inductive single largest load~~ing~~ that the DGs could experience. INSERT SR 3.8.1.9

~~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;~~

~~b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and~~

~~c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.~~

(continued)

<u>INSERT SR 3.8.1.9</u>

when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 580 kVAR for DG-1, 760 kVAR for DG-2, and 1015 kVAR for DG-3. However, if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

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.

1 Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.8,

C

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 ~~using a power factor ≤ 0.9~~. The~~is~~ese power factor~~s~~ ~~is chosen to be~~ are representative of the actual design basis inductive loading that the DG would experience.

4 8 at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3

8 1 takes into consideration the plant conditions required to perform the Surveillance, and is

C B C

The ~~18~~ 24 month Frequency is ~~consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is~~ intended to be consistent with expected fuel cycle lengths.

4 8 Insert SR 3.8.1.10a

C

This 1 SR has been modified by ~~a~~ two Note~~s~~ 5. The reason for ~~the~~ Note 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.

8 INSERT SR 3.8.1.10b

B

11

~~[ 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)

INSERT SR 3.8.1.10a

8

when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. 4 B B

8 INSERT SR 3.8.1.10b B

Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the reactive load may be reduced to maintain excitation current within the continuous rating. However, the excitation current shall be maintained $\geq$ 90% of the continuous rating of 142.4 amps for DG-1 and DG-2 and 100 amps for DG-3. This is to avoid conditions where the generator excitation system continuous rating limits can be exceeded or excessive transients can challenge equipment ratings due to network disturbances or spurious operation of breakers in the AC distribution system. B C

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

(11)

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.11

1C

Consistent with (1.9) (12)

(1) C.2.2.4

~~As required by~~ Regulatory Guide ~~1.108~~ (Ref. ~~9~~), paragraph ~~2.a.(1)~~, 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 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.

(3) and energization of permanently connected loads

(1) (5) (15) (1) for Division 1 and 2 and 18 seconds for Division 3 are

The DG auto-start time of ~~10~~ seconds ~~is~~ derived from requirements of the accident analysis ~~to respond~~ to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

for responding (3) 1C

(1) (Ref. 16)

The DG-3 18 second start time includes the Loss of Voltage-Time Delay Function Specified in LCO 3.3.8.1.

(1)

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 ~~[18]~~ 24 months ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1),~~ takes into consideration ~~unit~~ 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 and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations ~~for [Division 1 and 2] DGs. [For the [Division 3] DG, standby conditions mean that the lube oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by natural circulation.]~~ 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 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.5, ~~This~~ 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) and operates for ≥ ~~[5]~~ minutes. The ~~[5]~~ minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

loading logic for loading onto offsite power. 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, ~~high pressure injection~~ 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.

1

24 4

The Frequency of ~~[18]~~ 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. ~~Operating experience has shown that these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

4

1

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 and 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 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.

1

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 12), 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, generator differential current,

1C

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

(9) (12) C.2.2.9 this Surveillance

Consistent with Regulatory Guide 1.~~108~~ (Ref. ~~9~~), paragraph ~~2.a.(3)~~, 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 ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3 ~~using a power factor ≤ 0.9~~. Th~~is~~ese power factor~~s~~ are ~~chosen to be~~ representative of the actual design basis inductive loading that the DG could experience. (8) (4) <Insert SR 3.8.1.14a>

The ~~[18]~~ 24 month~~]~~ 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 of excitation current or 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.

(8) <INSERT SR 3.8.1.14b>

(continued)

## INSERT SR 3.8.1.14a

8 when running isolated from offsite power. To meet these power factor limits, the ~~DGs must be loaded to the following~~ reactive values when the SR is performed; 4 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. 1B

## 8 INSERT SR 3.8.1.14b 1B

Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. 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 grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the reactive load may be reduced to maintain excitation current within the continuous rating. However, the excitation current shall be maintained $\geq$ 90% of the continuous rating of 142.4 amps for DG-1 and DG-2 and 100 amps for DG-3. This is to avoid conditions where the generator excitation system continuous rating limits can be exceeded or excessive transients can challenge equipment ratings due to network disturbances or spurious operation of breakers in the AC distribution system. B C

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15

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~~ 15 seconds. The ~~10~~ 15 second time is derived from the requirements of the accident analysis ~~to~~ for respond~~ing~~ to a design basis large break LOCA (Ref. 16).

8 15 3 1 15 1

The ~~[18 months]~~ 24 4 Frequency ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9) paragraph 2.a.(5).~~ takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. 1

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 full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. ~~The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.~~ 8 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.

1 8

SR 3.8.1.16

~~As required by~~ Consistent with Regulatory Guide 1.~~108~~ 9 (Ref. ~~9~~ 12), paragraph ~~2.a.(6)~~ C.2.2.11, this Surveillance ensures that the manual synchronization and ~~automatic~~ 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 and can receive an auto-close signal on bus undervoltage, and the individual load ~~sequence~~ timers are reset. 1 1

The Frequency of ~~[18 months]~~ 24 4 ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).~~ 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

(1) ~~paragraph 2.1.(6), and~~ 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 3.8.1.17

(1) Consistent w/ Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.13, Demonstration of the parallel (1) 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. ~~13~~ 18), paragraph 6.2.6(2). (1)

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in 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 ~~[18~~ (4) 24 month~~]~~ Frequency (1) ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(8),~~ takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. (1) (9)

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

11

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

1

Since the DG-3 Loss of Voltage-Time Delay Function is bypassed during an ECCS initiation signal, a 15 second DG-3 start time applies, consistent with the DBA LOCA analysis (Ref. 16).

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of 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 ~~[18]~~ 24 months 4 takes into consideration plant conditions required to perform the Surveillance ~~and is intended to be consistent with an expected fuel cycle length of [18 months]~~. 1 9 5

1C

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove 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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.~~108~~ 9 (Ref. ~~9~~ 12), paragraph C.2.2.14. 1

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

6

Brackets added per TSTF-37.

[~~Diesel Generator Test Schedule~~

~~The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.~~

~~According to Regulatory Guide 1.9 (Ref. 3), Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.~~

~~The Frequency for accelerated testing is 7 days, but no less than 24 hours. Tests conducted at intervals of less than 24~~]

(continued)

BASES

SURVEILLANCE REQUIREMENTS

6

[ Diesel Generator Test Schedule (continued)

Hours may be credited for compliance with Required Actions. However, for the purpose of re-establishing the normal 31-day Frequency, a successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts, and the consecutive test count is not reset.

A test interval in excess of 7 days (or 31 days, as appropriate) constitutes a failure to meet SRs and results in the associated DG being declared inoperable. It does not, however, constitute a valid test or failure of the DG, and any consecutive test count is not reset. ]

Brackets added per TSTF-37

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter ~~[8]~~. (4)
3. FSAR, Figure 8.3-23. (1)
4. FSAR, Tables 8.3-1, 8.3-2, and 8.3-3.
5. (~~3~~) Safety (1) ~~Regulatory~~ Guide 1.9, Revision 0, March 1971 (1)
6. (~~4~~) FSAR, Chapter ~~[6]~~ (4)
7. (~~5~~) FSAR, Chapter ~~[15]~~ and 15F. (5)
8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). (1)
9. (~~6~~) Regulatory Guide 1.93, Revision 0, December 1974 (1)
10. (~~7~~) Generic Letter 84-15, July 2, 1984.
11. (~~8~~) 10 CFR 50, Appendix A, GDC 18.
12. Regulatory Guide 1.9, July 1993. (1)
13. (~~9~~) Regulatory Guide 1.108, Revision 1, August 1977 (1)
14. (~~10~~) Regulatory Guide 1.137, Revision 1, October 1979.

~~11. ANSI C84.1, 1982.~~ (1)

17. (~~12~~) ASME, Boiler and Pressure Vessel Code, Section XI.
18. (~~13~~) IEEE Standard 308-1974 (1)

15. Supply System Calculations Nos, E/I-02-87-07 and E/I-02-90-01.
16. FSAR, Section 15.F.6. (1)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized division.

8 {2}

C.1

When the HPCS is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS is not available. Since these sources only affect the HPCS, the HPCS is declared inoperable and the Required Actions of ~~the affected Emergency Core Cooling Systems LCO entered.~~

{3} LCO 3.5.2, "Emergency Core Cooling Systems - Shutdown" entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.10 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering HPCS will still perform its function, absent an additional single failure. 1C

8 {2}

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required

(continued)

## INSERT B 3.8.2 BKGD-A

Additional onsite storage is also provided by the auxiliary boiler fuel storage tank. The quality of the fuel in this tank is maintained in accordance with the requirements for the fuel stored in the DG storage and day tanks. However, no credit for accident mitigation is allowed for the quantity of the fuel stored in the auxiliary boiler fuel storage tank.

## INSERT B 3.8.2 BKGD-B

Fuel oil is transferred from each storage tank to its respective day tank by a transfer pump associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated locally and is provided with high and low level switches which actuate alarm annunciators in the main control room. The transfer pump on the filter polishing skid is used to move fuel oil from the auxiliary boiler fuel storage tank to each of the DG storage tanks. The auxiliary boiler and filter polishing systems and associated components are not required to conform to all of the guidelines in Regulatory Guide 1.137 (Ref. 2), because failure of a component or rupture of the piping would not result in the loss of a DG.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory (combined inventory in the DG lube oil sump(s) and in the warehouse) 3 is available to support at least 7 days of full load operation for each DG. The ~~500 gal~~ 330 gallon 8 requirement for Divisions 1 and 2 DGs and the 165 gallon requirement for Division 3 DG are 8 ~~is~~ based on the DG manufacturer's consumption values for the run time of the DG. 3 Normally, sufficient volume is maintained in the DG lube oil sump(s) to meet the 7 day requirement (Adequate inventory is maintained when the DG lube oil sump(s) are > 9 inches above the lower mark on the dipstick(s) with the DG secured and the lube oil circulating pump off). However, implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage (s) 1 location to the DG when the DG lube oil sump ~~does~~ do not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level (the lower mark on the dipstick(s)) 3.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests ~~listed below~~ of new fuel oil prior to addition to the storage tanks 3 are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between ~~receipt~~ the sample (and corresponding results) 3 of new fuel and ~~conducting the tests~~ addition of new fuel oil to the storage tanks 3 to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil 1 (in accordance with ASTM D4057-{ 88 4 } (Ref. ~~6~~ 7); 1 )

b. Verify in accordance with the tests specified in ASTM D975-{ 94 } (Ref. ~~6~~ 7) that (1) the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 {or an API gravity at 60°F of ≥ 27° and ≤ 39°} 3 ~~,~~ a ; (2)

(1) the sample has an API gravity of within 0.3° at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or 1

{ C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, ~~and~~ a flash point of ≥ 125°F; and

a water and sediment content of ≤ 0.05% volume when tested in accordance with ASTM D1796-83 (Ref. 7) or (1)

If gravity was not determined by comparison with the supplier's certification; and (3) (1)

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-{ } (Ref. 6). (93) (4) (7) (1)

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks. C

(3) ~~Within 31 days~~ following the initial new fuel oil sample, (94) (4) the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-{ } (Ref. 6) (7) (1) are met for new fuel oil when tested in accordance with ASTM (4) (94) D975-{ } (Ref. 6), except that the analysis for sulfur (14) (7) ~~may be performed~~ in accordance with ASTM D1522-[ ] (1) (Ref. 6) or ASTM D2622-[ ] (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs. INSERT SR 3.8.3.3 (3) C

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

(93) (4) (7) (1)

Particulate concentrations should be determined in accordance with ASTM D2276-{ }, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. (6) [For those designs in which the total volume of stored fuel oil is contained in two or more interconnected tanks, each tank must be considered and tested separately.] C

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate

(continued)

8 The charger shall be loaded, to a minimum, at three separate and sequential load ratings, 50%, 75%, and 100%, for ≥ 30 minutes at each load rating.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. ~~9~~ 12), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

1

8 Insert SR 3.8.4.6

A

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these ~~18~~ 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

8

8 ~~This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.~~

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

Insert SR 3.8.4.7

The Surveillance Frequency of ~~18~~ 24 6 months is ~~consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.~~

8

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test once per 60 months.

(continued)

8 INSERT SR 3.8.4.6

The 100% load rating for the Divisions 1 and 2 125 V battery chargers is 200 amps, for the Division 3 125 V battery charger is 50 amps, and for the Division 1 250 V battery charger is 400 amps. C

8 INSERT SR 3.8.4.7

acceptable, given unit conditions required to perform the test and the other requirements existing to ensure adequate battery performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

Appendix C

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C ~~Allowable Value~~ limit for float voltage is based on IEEE-450, Appendix C (Ref. 8), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity (≥ ~~[~~1.190~~]~~), is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that ~~the effect of a highly charged or new cell does not mask overall degradation of the battery.~~

a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote ~~(~~b~~)~~ ~~in Table 3.8.6-1~~ requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of acceptable overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charg~~er~~ing current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 8). Footnote ~~(~~c~~)~~ ~~to Table 3.8.6-1~~ allows the float charge

(continued)

8 — 7

BASES

LCO (continued)

subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. ~~OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated [inverter via inverted DC voltage, inverter using internal AC source, or Class 1E constant voltage transformer].~~

1

<INSERT B 3.8.7 LCO>

In addition, tie breakers between redundant safety related AC ~~, DC, and AC vital bus~~ power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the ~~affected redundant~~ electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystems) are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

1

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and.

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and DC electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.~~10~~ 9, "Distribution Systems—Shutdown."

7

8

ACTIONS

A.1

With one or more Division 1 or 2 required AC buses, load centers, motor control centers, or distribution panels ~~(except AC vital buses)~~, in one division inoperable, the

1

(continued)

## B 3.10 SPECIAL OPERATIONS

### B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3).

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation, decay heat, 1 and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. 1A

With increased reactor vessel RCS 3 fluence over for time, the minimum allowable vessel temperature increases ~~at~~ a given pressure. Periodic updates to the ~~RPV~~ P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. ~~Hydrostatic and leak testing will eventually be required with minimum reactor coolant temperatures > 200°F.~~ 4

5 ~~The hydrostatic test requires increasing pressure to [ ]% of design pressure (1250 psig) or [ ] psig, and because of the expected increase in reactor vessel fluence, the minimum allowable vessel temperature according to LCO 3.4.11 is increased to [ ]°F. This increase to [ ]% of design pressure does not exceed the Safety Limit of 1375 psig.~~

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

(except for an air bubble for pressure control)

1

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 200°F, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.8, "Reactor Coolant System (RCS) Specific Activity," are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

1A

1

, and high pressure core spray

1

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure coolant injection ~~and~~ low pressure core spray subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS—Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of

(continued)

BASES

(Ref. 3) 1

APPLICABLE SAFETY ANALYSES (continued)

the NRC Policy Statement (Ref. 3) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

6

performance of inservice leak and hydrostatic testing results in the inoperability of subsystems required when > 200°F (i.e., MODE 3).

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 200°F, can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 200°F, while ~~the ASME inservice test itself requires the safety/relief valves to be gagged, preventing their OPERABILITY~~.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purposes of performing either an inservice leak or hydrostatic test.

C

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation.

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 200°F. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
BASES SECTION 3.10 - SPECIAL OPERATIONS

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 proper LCO number has been provided.

3. Typographical/grammatical error corrected.

4. The hydrostatic test is already required at reactor coolant temperature > 200°F. Therefore, this sentence has been deleted.

5. This paragraph is considered an unnecessary level of detail for these Bases because the subject is adequately presented in the Bases for proposed LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." In addition, the last sentence is being deleted since the LCO is not exempting the Safety Limit from being met during a hydrostatic test. C

6. The ASME inservice test does not require the SRVs to be gagged. Therefore, a valid reason for this LCO exception has been provided.

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

8. The Bases have been changed to be consistent with the Specification.

9. Editorial change made for enhanced clarity or to be consistent with similar statements in other places in the Bases.

10. The Bases have been changed to reflect those changes made to the Specification.

11. The correct power level (corresponding to the analysis value) is 10% RTP. As written, the power level corresponds to the low power setpoint, which is higher.

12. This Bases section has been deleted because the associated Specification has been deleted.

13. This statement has been deleted since it is duplicative of the previous sentence.

14. This change was approved to be made in NUREG-1434, Revision 1 per change package BWR-18, C.81, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Revision 1. B

15

220 total